Service Date: November 8, 1989

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER Of The Application Of	)	UTILITY DIVISION
MONTANA-DAKOTA UTILITIES COMPANY,	)	
a Division of MDU Resources Group,	)	DOCKET NO. 88.11.53
Inc., for Authority to Establish	)	
Increased Rates for Gas Service.	)	ORDER NO. 5399b

FINAL ORDER

APPEARANCES

FOR THE APPLICANT:

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FOR THE MONTANA CONSUMER COUNSEL:

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FOR THE COMMISSION:

Robin McHugh, Staff Attorney
Joe Holliman, Staff Economist
Mark Lee, Staff Rate Analyst

BEFORE:

HOWARD L. ELLIS, Commissioner & Hearing Examiner
WALLACE W. "WALLY" MERCER, Commissioner
DANNY OBERG, Commissioner

PART 1
INTRODUCTION

On November 28, 1988 Montana-Dakota Utilities Company (MDU or Company) filed an application with the Montana Public Service Commission (Commission) for approval of a revenue in-crease of $1,623,009, or an overall increase of 3.64 percent.

The filing was assigned Docket No. 88.11.53. Following the issuance of a Proposed Procedural Order, a Procedural Order was issued on January 30, 1989. The Procedural Order contemplated a hearing date beginning May 16, 1989. Intervention was granted to the Montana Consumer Counsel (MCC), Exxon and Conoco. Only MCC actively participated in the Docket.

On February 17, 1989 the Commission issued an interim order in this Docket. See Interim Order No. 5399. In the interim order the Commission authorized a rate change designed to increase annual natural gas revenues by $411,924.

On March 30, 1989 the Commission received a stipulation between MDU and MCC on the proper cost of capital and capital structure for MDU in this proceeding. No other intervenor opposed the stipulation. The MCC and MDU stipulated as follows:

Description	Ratio	Cost	Weighted Cost
Long-Term Debt	53.710%	10.074%	5.411%
Preferred Stock	4.815	4.834	.233
Common Stock	41.475	12.500	5.184
	100.000%		10.828%

Following a noticed meeting with MCC and MDU, wherein the merits of the stipulation were discussed, the Commission issued an order approving the stipulation. See Order No. 5399a, May 2, 1989.

On November 18, 1988 the Commission issued its final order in MDU Docket No. 87.12.77. See Order No. 5379. In Docket No. 87.12.77 MDU requested authority to (among other things) flexibly price its service under Rates 81, 82 and 90. Rates 81 and 82 are for interruptible natural gas transportation services; Rate 90 is for interruptible natural gas sales service. The Commission approved flexible pricing for Rates 81, 82 and 90, but conditioned that approval as follows:

Because of costing concerns these tariffs will automatically terminate 15 months after final approval. Continued flexibility may be granted upon MDU's filing and Commission consideration of a long-run marginal cost study for service on all rates and tariffs, but especially Rates 81, 82 and 90. If a proceeding is not completed at the end of 15 months, all transportation service will be priced at the last tariffed "margin" based prices. Similarly, service on Rate 90 will revert to the otherwise applicable tariff.

Order No. 5379, Paragraph 51.

On March 27, 1989 the Commission received a motion from MDU for an order vacating the Procedural Order in this Docket (88.11.53). MDU made the request so that the long-run marginal cost study required in Order No. 5379, could be incorporated into this proceeding. (See paragraph 4, supra.) The Commission granted MDU's Motion and on March 30, 1989 issued a Notice of Commission Action, Order and Revised Procedural Schedule.
The new schedule contemplated an opening date of hearing on August 8, 1989. That date was subsequently changed to August 9, 1989. In addition, MDU agreed to waive the time period specified in Sec. 69-3-302(2), MCA, to October 27, 1989.

Following proper notice, hearing was held on this expanded Docket beginning August 9, 1989. At the hearing MDU objected to the Commission staff introduction into evidence of all responses to Commission staff data requests. In addition, MDU objected to the introduction into evidence by MCC of certain data responses. The Commission took these objections under advisement and will address them in this order. In addition, MDU agreed at the hearing to waive the time period specified in Sec. 69-3-302(2), MCA, by two weeks beyond the previous deadline of October 27, 1989. The new deadline was subsequently waived one additional week (to November 17, 1989) to accommodate changes in the post-hearing briefing schedule.

This order is divided into five parts. Part 1 makes up the introduction; Part 2 will address MDU's objection to the introduction of evidence; Part 3 will address cost of capital and revenue requirements; Part 4 addresses cost of service; and Part 5 rate design.

PART 2

RESPONSE TO MDU'S OBJECTIONS TO THE INTRODUCTION OF EVIDENCE

MDU objected at hearing to the introduction into evidence by Commission staff of responses to Commission staff data requests. In support of this objection MDU argues in its opening brief that evidence is introduced by parties to prove something, and the attempt to introduce evidence by staff indicates that the staff has assumed an advocacy role in the hearing process. The staff may assume an advocacy role, MDU continues, but only by complying with the provisions of Section 69-2-102, MCA (69-2-102). Further, MDU contends that the Commission's attempt to introduce evidence, when it has not openly advocated a position through an advocacy staff, is inherently violative of the due process provisions of the Montana and United States Constitutions." MDU Opening Brief, p. 23. MDU also charges that an attempt to introduce evidence violates certain provisions of the Montana Administrative Procedures Act (MAPA). MDU argues that the Commission's role in the ratemaking process is primarily to act as a tribunal. By this, MDU apparently means that the Commission must primarily sit as a judge, accepting and ruling on record evidence introduced only by parties to the case. Because the Commission does not accept the assumptions underlying MDU's argument, does not accept MDU's interpretation of 69-2-102, and does not agree that staff's introduction of evidence violates MDU's due process rights, MDU's objection is overruled.

Commission staff has clear authorization under Commission rules to introduce evidence into the record. At ARM 38.2.601(n) the Commission staff is made exempt from party status. At the same time, however, Commission rules state that, "The Commission staff shall have the full rights and responsibilities of parties under these rules, ..." Id. The rights of parties are specified under the rules as follows: "At any hearing, all parties shall be entitled to enter an appearance, introduce evidence, examine and cross-examine witnesses, make arguments, and generally participate in the conduct of the proceeding." ARM 38.2.3902(1). It is, therefore, plain that nonparty Commission staff can introduce evidence into the record.

The designation of nonparty status to Commission staff, while retaining for staff the rights and responsibilities of parties, is consistent with the role of the Commission and the role of Commission staff in the ratemaking process. MDU mischaracterizes these roles in its brief, requiring some comment from the Commission.

The Commission's role in utility rate cases is to investigate in furtherance of its obligation to set reasonable and just rates for the provision of utility service. Commission rule ARM 38.2.302(1) clearly states that, "The proceedings before the Commission are investigative on the part of the Commission, although they may be conducted in the form of adversary proceedings." When a utility seeks authority in a rate case to change its rates it bears the burden of demonstrating that existing rates are unreasonable. Intervening parties, usually composed of consumers of the utility product, challenge the utility's position and often advance their own adversary position on the reasonableness of the requested rate change. The Commission's role in the process is not to advance any particular client or constituency interest, but to set the appropriate rate.[1]

The Commission's obligation to set just and reasonable rates carries with it an independent responsibility to investigate all the facts surrounding an applicant utility's operations. Much valuable information on the utility's operations is provided by the utility with its application, and additional valuable information is provided through the discovery and testimony of intervenors. But the Commission would be shirking its obligation if it let the evidentiary record stand with only the information provided by parties to the case. Other useful information and evidence may be neglected by the parties and it is the Commission's duty to see that this material gets on the record so that it may be considered in reaching a decision.

It is commonly and legally accepted that administrative decision-makers are fundamentally different from judicial decision-makers. One obvious difference is that administrative decision-makers are not bound by the record established by adversary parties, but may themselves supplement the record by the kind of independent investigation referred to above. An important statement to this effect was made by the Supreme Court as follows:

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[1] An appropriate, or just and reasonable, rate depends on the facts and circumstances of each particular case. Generally speaking, a just and reasonable rate should: 1) allow the utility sufficient revenues to efficiently maintain adequate service while also earning a fair return on assets devoted to utility service, and 2) it should extract the absolute minimum from consumers of utility service consistent with the adequate service that consumers expect and the law requires.

Federal Communications Commission vs. Pottsville Broadcasting Co., 309 U.S. 134, 142-143 (1939) (footnotes omitted) (emphasis added).

In recognition that the Commission, by itself, may not be able to adequately carry out its independent investigatory function, the legislature gave the Commission the power "to appoint stenographers, inspectors, experts, and other persons whenever deemed expedient or necessary by said commission to the proper performance of its duties." 69-1-109, MCA. The Commission has, of course, hired staff pursuant to this statute and it has delegated to it the power and responsibility to investigate in rate cases; and to make sure, through introduction of data responses or other evidence, or through cross-examination, that the record, to the extent possible, contains all the facts necessary to support a variety of reasoned decisions on the issues, and to allow the Commission to set a just and reasonable rate.
Additionally, the Commission staff reviews the record with the Commission and may make recommendations with respect to ultimate decision. This last is clearly contemplated by Section 2-4-612(7), MCA, which reads, "The agency's experience, technical competence, and specialized knowledge may be utilized in the evaluation of evidence."

In all events, in general rate cases, the Commission staff acts in an advisory and investigatory capacity. The Commission staff does have an interest, the same as that of the Commission described above: that rates be set at precisely the point that will maximize ratemaking objectives. However, staff investigation, analysis and advice is not on behalf of any client or constituency group, either utility or consumer. Commission staff is not an advocate, and it does not secretly advocate by preparing positions and attempting to prove them at hearing. The Commission staff's introduction of evidence and its cross-examination of witnesses at hearing does not transform it into the role of an advocate. Rather, such activities are consistent with the investigatory responsibility of the Commission toward the goal of just and reasonable rates.

MDU argues that if the Commission assumes an advocacy role it must comply with provisions of 69-2-102. As already noted, the Commission has not assumed an advocacy role in this case, nor would the Commission assume an advocacy role in any but the most unusual rate case. Furthermore, if the Commission were to assume an advocacy role, the provisions of

69-2-102 would have little, if any, relevance.[2] Because 69-2-102 has been cited to the Commission several times by MDU, and recently by the Montana Power Company, the Commission will discuss it here in some detail. See Montana Power Company, Brief on Motion For Reconsideration, Docket Nos. 88.6.15 et al., p. 15, October 2, 1989.

Section 69-2-102, reads as follows:

Role of commission when consumer counsel protests. In any case involving an application by a regulated entity to the commission for authority to increase its rates which is actively contested by the consumer counsel, the commission shall leave representation of the interests of consumers to the consumer counsel when he timely petitions to become a party to such case. Nothing contained herein prohibits the commission or its staff from investigating and interrogating in any hearing to clarify the case or present an issue. Evidence may be introduced by the commission on an issue that has not been adequately addressed by any party if the commission first requests counsel of record to address such issue and such counsel fails to introduce sufficient or adequate evidence.

MDU interprets this section as limiting Commission power to introduce evidence to cases where parties fail to introduce sufficient evidence, or adequately address an issue, after having been asked by the Commission to do so. Since the Commission did not request that any party introduce evidence or ad dress an issue, MDU contends that the Commission's introduction of evidence means that the Commission has assumed an advocacy role in violation of this section. The Commission finds that, when measured against legislative history and reasonable statutory interpretation, MDU's position is not convincing.

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[2] The Commission may assume an advocacy role on behalf of consumer interests if the Consumer Counsel is not a party. In such a case, Section 69-2-102, MCA, does not control or limit Commission action. That section controls when Consumer Counsel intervenes.

The first sentence is clear and unambiguous: when the Consumer Counsel intervenes he represents consumer interests, and the Commission does not. This is consistent with the Commission's role, described earlier, wherein the Commission sets rates, it does not represent any particular interest.[3]

The second sentence of 69-2-102 indicates that nothing in the section should be construed as indicating a legislative intent to alter the independent investigatory role of the Commission and its staff in rate cases. Coming on the heels of the first sentence, it is clear that the investigation referred to in the second sentence is not on behalf of consumer interests, but toward the end of just and reasonable rates. The Commission finds implicit in the second sentence the authority for both the Commission and its staff to introduce evidence into the record. The Commission concludes that there would be no point to investigation in a rate case, if the fruits of that investigation could not be considered when setting rates. Since most evidence can not be considered that has not been formally introduced into the record, the Commission must be allowed to introduce the results of its own investigation at hearing.[4] Interrogation (cross-examination) at hearing to clarify the case or present an issue is obviously part of the record. It makes no sense to the Commission that the legislature would sanction including Commission oral interrogation at hearing as part of the record, but would prohibit the Commission introduction of responses to written interrogatories (data requests). They are, in essence, the same thing.

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[3] Of course, the establishment of just and reasonable rates, as a major component of the regulation of natural monopolies, has long been considered by the people of Montana to be in the public interest.

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[4] The Commission may take administrative notice of certain kinds of nonrecord evidence.

The third sentence of 69-2-102, MCA, reads that evidence may be introduced by the Commission on an issue that has not been adequately addressed by any party if the commission first requests counsel of record to address such issue and such counsel fails to introduce sufficient or adequate evidence."

The Commission finds that only a very narrow interpretation of this sentence is consistent with the first two sentences and statutory history. That is, as authorization to the Commission to go to the expense of hiring an outside expert to present evidence in the event that existing parties fail to address an issue adequately. Such expert would present evidence on behalf of the Commission in its role as ratemaker. He would not present it on behalf of consumers, as the Commission is specifically directed to leave representation of consumers to the Consumer Counsel when he is a party. This interpretation is consistent with the intent of the legislature (see below) to prevent the inefficiency of costly duplication of effort on the part of the Commission and Consumer Counsel. Section 69-2-102 eliminates that duplication, but the third sentence leaves the Commission the option, an option that admittedly has never been exercised, to buttress the record through an outside expert in a case where the evidence of parties, and by implication evidence from its own staff, is deemed insufficient. The third sentence gives the Commission another method for developing a complete record in rate cases. It is a method that has been limited by the legislature for reasons of cost. MDU's interpretation of the third sentence, which is that the Commission is limited in its power to get evidence on the record, would have the effect of repealing the second sentence which gives the Commission and its staff power to add to the record independent of parties to the case.

Statutes must be interpreted, if possible, to give all parts meaning. See Section 1-2-101, MCA. Accepting MDU's argument would clearly violate that principle of statutory construction.

The legislative history of 69-2-102, MCA, makes very clear that the legislature intended to prevent the duplication of effort and waste that would result from both the Consumer Counsel and the Commission representing consumer interests. The minutes of the Senate hearing on this statute state that "Senator Towe, District 34, sponsor of the bill, stated the bill simply clarifies the role of the Consumer Counsel and Public Service Commission to avoid duplication of efforts." The minutes of the House hearing state that, "Sen. Towe stated it would be a tragedy if both the Public Service Commission and the Consumer Counsel hired very expensive people to come here to prepare a case. We should eliminate this duplication." Prior to the passage of 69-2-102, it was not uncommon for there to be some duplication of effort in the form of both the Commission and the Consumer Counsel hiring expert witnesses to represent consumers. Section 69-2-102, eliminates that duplication, but it also leaves open the possibility, remote though it may be, that the Commission could introduce evidence, independent of parties and staff, in the interest of establishing a more adequate record.

MDU's interpretation of 69-2-102, as transforming the Commission into a tribunal, similar to a court, would not only make that statute internally inconsistent, it would radically alter the role of the Commission as set out in Title 69, and as traditionally understood. There is no evidence that by the passage of 69-2-102, the legislature intended such a major transformation in Commission function and the manner in which utility rates are determined in Montana.

MDU also objected at hearing to the introduction by MCC of data responses that were not relied upon by MCC in the preparation of its testimony. This represents another attempt by MDU to constrict the record in this case. MDU's objection is overruled. MDU, and other utilities, should be aware that it is the Commission's strong conviction that all records before it should include all relevant evidence. The Commission will liberally construe the rules of evidence and its own procedural orders, and generally will admit evidence that appears only marginally relevant, but may prove crucial in determining just and reasonable rates. The Commission, of course, is bound by and adheres to rules of due process. In this context, due process dictates that all parties must have notice of the evidence that the Commission may consider in reaching a decision, and the opportunity to respond to, explain, or challenge that evidence.

MDU has had ample notice of the evidence that it objects to here, and has had the opportunity to submit evidence of its own. To the extent that MDU is aggrieved in the final order in this Docket it has the opportunity to make further argument on reconsideration. And, to the extent that MDU believes that it has been surprised by a new issue, and that it has not had the opportunity to respond, it can request rehearing. MDU cites to paragraph 12 from the Procedural Order in this Docket which indicates in part that, "Introduction of new issues or data in new areas will be carefully scrutinized and disallowed unless reasonably related to issues earlier identified in the application, in Commission orders or in testimony prefiled in conformance with this order." MDU has failed to demonstrate to the Commission how the introduction by MCC of the data responses at issue constitutes the introduction of a new issue or data in a new area. If MCC has had a "hidden agenda" in this case, it would not make sense to hide it indefinitely. Presumably MCC would have to argue any "hidden agenda" in its brief, at which time MDU could challenge such argument on reply, or, once again, it could ask for a rehearing where it could attack head-on the erstwhile "hidden agenda."

While the Commission overrules MDU's objections to the introduction of evidence, and finds that there has been no denial of due process to date in this Docket, the Commission is concerned about the frequent allegations of unfairness in Commission proceedings. Therefore, the Commission has recently indicated that it will open a docket to solicit comments and suggestions regarding its decision making process. See Montana Power Company, Order on Motions for Reconsideration, Docket No. 88.6.15, Order No. 5360e, paragraph 80. MDU is invited to participate in that docket.

PART 3
REVENUE REQUIREMENTS
I. COST OF CAPITAL

On March 30, 1989 the Commission received from MDU and MCC a Stipulation regarding capital structure and associated capital costs. On May 1, 1989 the Commission issued Order No. 5399a which approved the stipulated cost of capital for purposes of this Docket. Order No. 5399a and the Stipulation are attached to this Order as Appendices A and B. The approved cost of capital is:

Description	Ratio	Cost	Weighted Cost
Long Term Debt	53.710%	10.074%	5.411%
Preferred Stock	4.815	4.834	.233
Common Stock	41.475	12.500	5.184
Total	100.000%		10.828%

II. REVENUES

Residential and Firm Commercial Sales

MDU and MCC agree on the level of revenues for the firm customer classes (i.e. residential and firm commercial).

Both parties proposed weather normalized loads for the 12 months ended June 30, 1988, converted a portion of interruptible commercial and industrial sales to firm commercial sales, eliminated the effects of a rate refund and made adjustments to annualize any rate changes that occurred after the test period. To affect these changes, both parties proposed the following adjustments:

Annualize December 1988 Rate Change	$(5,271,975)
Weather Normalization	3,855,930
Interruptible Sales Converted to Firm	330,982
Provision for Rate Refund	28,504

These proposed adjustments are consistent with prior Commission decisions and appear to be reasonable for the purposes of this proceeding. Therefore, the Commission accepts these adjustments at the levels proposed by both parties.

Transportation Revenues

Under the Company's Margin Sharing Mechanism, zero volumes and $0 revenues would be included for interruptible sales and transportation services. MDU foresees extreme volatility in the markets for interruptible sales and transportation and is hesitant to try and establish representative volumes.

Rather, MDU proposed to credit the entire margin from interruptible services back to the firm customers at a later date. MDU did not propose specific transportation volumes for use in determining pro forma transportation revenues in the event its Margin Sharing Mechanism was rejected by the Commission.

MCC proposed that calendar year 1988 volumes be used for Rates 81 and 82. MDU pointed out in rebuttal testimony that MCC witness Al Clark used incorrect rates to calculate Rate 81 and 82 revenues in his direct testimony (MDU Exh. H, pp. 5-6).

Clark corrected this error in his supplemental testimony. MCC's recommendation explicitly assumed that Rate 97 volumes would be lost to the Company because that schedule has been eliminated from the Company's tariffs (MCC Exh. 10, p. 14). However, Mr. Clark did state "If this assumption proves false, a further adjustment to MDU's revenue requirement will be required" (MCC Exh. 10, pp. 14-15).

MDU did not rebut the specific volumes proposed by Clark. Rather, MDU witness Don Ball discussed the current market volatility associated with interruptible transportation volumes but did not offer alternative volumes for Commission consideration (MDU Exh. H, pp. 4-5).

During the hearing, Mr. Ball was asked about transportation volumes experienced by the Company during the first half of 1989:

Q. Has the Company noted a significant movement of customers from interruptible sales to transportation since the approval of flexible rates?

A. Speaking only for the state of Montana, there has been some movement of customers from sales to transportation, but the major thing we are seeing with transportation is that we are, at least so far, regaining some of the customers that were not using gas under the trans portation tariffs, and some of the customers are signing very short term contracts, primarily the larger industrial users; they are signing contracts for six months.

Q. Does that indicate that MDU has experienced additional throughput on its system in Montana as a result of the flexible rates?

A. Yes, it has, especially in the case of the large industrial users. Some of those have come back on and are using more volumes. But we have had to flex the rate to achieve that so that in terms of a margin received by the Company, it is not as much as we would achieve at the ceiling rate, but it is certainly better than no margin at all.

(TR pp. 244-245)

This line of questioning revealed three important facts to the Commission: 1) there has been some amount of volume switching from interruptible sales to transportation; 2) the Company does not consider volume switching to be the major impact of flexible pricing and did not indicate it would have a negative effect on revenues; and 3) the industrial transportation volumes proposed by MCC are probably understated.

For additional evidence regarding transportation volumes, the Commission reviewed MDU's response to PSC-32. That response indicated MDU transported 41,561 dk under Rate 81 and 431,185 dk under Rate 82 during only the first three months of 1989. Clark's proposal recognized volumes of 14,202 dk for Rate 81 and 351,788 dk for Rate 82 for an entire 12 month period.

This information also suggests that MCC's proposed transportation volumes are understated.

Pursuant to the decision to reject MDU's proposed Margin Sharing Mechanism (MSM), the Commission finds that MCC's proposed transportation volumes should be accepted in this proceeding, with one modification: 861,117 dk of calendar year 1988 Rate 97 volumes should be included at the floor price for Rate 82. The Commission used the floor price because of Mr. Clark's explanation that such a rate was the most reasonable to use if the Commission determined that calendar year Rate 97 volumes should be recognized (MCC Exh. 10, p. 14). This decision results in a $247,492 decrease in revenues for purposes of this proceeding.

Interruptible Industrial Sales

As explained in the transportation section, zero volumes and $0 revenues would be included for interruptible industrial sales under the Company's proposed Margin Sharing Mechanism. MDU did not propose specific volumes for use in determining pro forma interruptible industrial sales revenues in the event its Margin Sharing Mechanism was rejected by the Commission.

MCC proposed adjusted calendar year 1988 volumes be used to establish representative industrial sales revenue levels. The adjusted volumes reflect a decrease in interruptible industrial sales volumes that the Company has moved to firm commercial sales.

MDU did not rebut the specific volumes proposed by Clark. Instead, Mr. Ball discussed the current market volatility associated with interruptible industrial sales volumes but did not offer alternative volumes for Commission consideration (MDU Exh. H, pp. 4-5).

During the hearing, Mr. Clark was questioned about abnormally high volumes that occurred during one of the months included in MCC's determination of representative volumes that it proposed be used in this proceeding:

Q. As I understand it, you recommended that 1988 actual industrial sales volumes be used, adjusted for volumes moved to firm sales; is that correct?

A. That's correct.

* * * * *

Q. Could you please refer to the October figure, just moving towards [sic] your left, does that not show volumes (of) 117,619?

A. Yes, it does.

Q. Do you believe that that is a representative figure in light of the fact that it far exceeds volumes for any of the other months, and if you do--

A. I can't answer that question. I used the annual volumes, and I didn't look at the months.

Q. Well, the question is, might it not be reasonable to, since this figure for October appears unrepresentative of the year as a whole, to throw those volumes out, or at least reduce them in arriving at representative volumes for the year?

A. I wouldn't recommend that unless you have some reason to throw them out. I don't know what caused that, quite frankly. I think conversely, looking at the same kind of numbers, you can see that the numbers in November and December look very low. Maybe they should be a little higher. All I am saying is that on the annual basis, I used those as representative. I didn't try to pick and choose among the months.

(TR pp. 220-221)

The Commission understands the point that Mr. Clark was making.

Any number of conditions could have caused the October volumes to be higher than the other months. Conceivably, one transportation customer's supply of gas was temporarily interrupted and the customer required gas on short notice that it could only acquire from MDU, or maybe the October volumes reflect corrections for previous under billings. The point is the Commission does not have before it enough information to reasonably conclude that Clark's volumes are not representative. Additionally, the Commission believes that MDU would have argued against Clark's industrial sales volumes (as it did when Clark double counted 5000 dk of commercial interruptible volumes) if the Company thought those volumes were abnormal.

In the absence of information from which the Commission could conclude Mr. Clark's proposed volumes are not representative, the Commission finds MCC's proposed interruptible industrial sales volumes to be reasonable in this proceeding.

This finding requires recognition of an adjustment to increase revenues by $112,029.

Interruptible Commercial Sales

As explained in the transportation section, zero volumes and $0 revenues would be included for interruptible commercial sales under the Company's proposed Margin Sharing

Mechanism. MDU did not propose specific volumes for use in determining pro forma interruptible commercial sales revenues in the event its Margin Sharing Mechanism was rejected by the Commission.

MCC proposed that adjusted calendar year 1988 volumes be used to establish representative interruptible commercial sales revenue levels. The adjusted volumes were to reflect the portion of interruptible sales volumes that the Company has moved to firm.

In rebuttal testimony, Mr. Ball stated that Clark double counted 5000 dk of sales (MDU Exh. H, p. 9). Mr. Ball claimed that Clark did not remove from interruptible commercial volumes the inter-company gas sales associated with MDU's electric power plants that were included in the firm commercial volumes proposed by both parties. Other than the double counting issue, MDU did not rebut the specific interruptible commercial volumes proposed by MCC. In lieu thereof, Mr. Ball discussed the current market volatility associated with interruptible commercial sales volumes but did not offer alternative volumes for Commission consideration (MDU Exh. H, pp. 4-5).

MCC admitted in its answer brief that the volumes were overstated by 5000 dk due to Clark's double counting of electric power plant volumes.

The Commission finds that Clark's proposal (adjusted to eliminate the double counting) results in reasonably representative interruptible commercial sales volumes and revenues to be used in this proceeding. Therefore, an adjustment that decreases revenues by $344,343 is warranted in this proceeding.

Base Rate Revenues

Upon reviewing both Parties' calculations related to gas sales, the Commission noticed a flaw associated with base rate revenues. MDU and MCC both rounded down the base rates to the nearest whole dollar, thereby ignoring several thousand dollars of includible revenues.

The Commission finds that an adjustment must be made to fully reflect base rate revenues. Thus, an $8,285 revenue increase must be included to fully reflect base rate revenues in this proceeding.

NSF Check Charge

MDU incurred 700 NSF checks during the test year. In this Docket, the Company is proposing a $10 charge on all NSF checks. Initially, MDU made no proposal related to the possible NSF charge revenues or related cost savings. Later, as a compromise, the Company admitted that such charges are about 50 percent effective and suggested that $3,500 (50% of 700 NSF checks at $10 per check) in additional annual revenues should be recognized in this proceeding (MDU Exh. H, p. 10). MDU's estimated per check NSF costs are $11, of which most are not avoidable in the near term (MDU Response to PSC-92).

MCC is neither supporting nor opposing the proposed NSF check charge. However, MCC does support some recognition of the changes in revenues and/or expenses that would result if the charge is approved by the Commission. Mr. Clark reasoned that the NSF charge would be effective in some instances and ineffective in others. Therefore, he surmised that the Company would likely see some combination of additional revenues and decreased expenses. Mr. Clark proposed that an expense reduction of $7,700 (700 NSF checks at $11 per check) be included to reflect the effects of an NSF charge.

The Commission agrees with MCC that some change in revenues and/or expenses must be recognized. At the same time, the Commission agrees with MDU that a 100 percent reduction in the expenditures required to process NSF checks is impossible to achieve because most of the costs are not avoidable in the near term.

The Commission accepts Mr. Ball's adjustment to increase revenues by $3,500. However, the Commission points out that some of the NSF processing costs are avoidable in the near term and reduced costs must also be reflected for the reduced number of NSF checks assumed in this adjustment. Based on information contained in the Company's response to PSC-92 the Commission estimates costs of $3.59 per NSF check are avoidable in the near term:

Mileage costs:	
Pickup the NSF Check from the Bank	$1.65
Deliver the NSF Notice to the Customer	1.65
Forms Used in Processing the NSF Check	0.29
Total per NSF Check	$3.59

Therefore, an expense reduction of $1,257 (50% of 700 NSF checks at $3.59 per check) must also be recognized in this proceeding.

Due to the minimal impact this issue has on revenues and expenses, the Commission did not perform a rigorous analysis of this issue from a revenue requirements perspective. A much more demanding examination would have been conducted if the revenue and expense impacts were more significant. As a result of this limited analysis, the Commission finds a $3,500 increase in revenues and a $1,257 expense decrease to be appropriate.

Late Payment Charge Revenues

MDU did not include in its filing revenues associated with its late payment charge, the test year amount of which is $19,371 (MDU Response to PSC-18). During the hearing, MDU's witness, Laurel Rick, explained the Company's reasons for not including these revenues in its filing:

> The late payment charges are booked below the line. And the Company and I firmly believe that this is the appropriate accounting for them because of the resultant short-term borrowing estimated savings, or costs savings. In other words, we are not expensing and likewise incurring additional savings from it because of the short-term borrowing costs. (TR pp. 126-127)

MCC also did not include these revenues in its proposed revenue levels; probably because MDU's response to PSC-18 was not provided until after MCC's testimony was filed. However, in response to PSC-128, Mr. Clark of MCC stated that these revenues should be reflected in this case for the reasons given by the Commission in the MDU electric Order in Docket No. 86.5.28.

In MDU's last electric rate case, Docket No. 86.5.28, the Commission found that late payment charges must be included as revenue (Order No. 5219b). That finding was based primarily on the fact that MDU's customers are bearing all of the costs to process the late bills and administer the late payment charge.

Clearly, MDU is ignoring this important fact when it concludes that these revenues should be booked below the line. It is worth noting that ALL other utilities under this Commission's jurisdiction having late payment charges freely include the revenues in calculating revenue requirements.

MDU's argument is that the Company does not include cash working capital requirements in its filings, and that the late payment charge revenues should be used to offset short-term interest expenses incurred by the Company to carry past due accounts. The Commission is not unsympathetic to this argument, however, if the Company has cash working capital requirements it should file with the Commission in the next rate case a lead-lag study to demonstrate the magnitude of such requirements.

The Commission finds that an adjustment to increase revenues by $19,371 is appropriate in this proceeding to reflect late payment charge revenues. Additionally, the Commission finds that in MDU's next rate case, gas or electric, the Company must include late payment charge revenues in its calculation of revenue requirements. The Company may be granted an exception to this finding in its next filing if a good faith effort is made by MDU to meet its burden of proof on this issue.

Gain on Sale of Property

During the test year, MDU sold its Bridger Office Building and realized a $29,453 gain on the sale which was not included in the Company's filing. The property value was included in the Montana rate base in this and other gas filings. All costs to maintain the property were included in previous gas rate filings and, thus, were borne by the ratepayers (MDU Response to PSC-230).

In the last MDU electric case, Docket No. 86.5.28, the Commission included in revenues the gain on the sale of a transmission line (Order No. 5219b). Similar treatment of a gain on property dispositions was afforded Butte Water Company (BWC) in Docket No. 86.3.7 (Order No. 5194a).

The Commission again finds that a gain on a sale of property must be included as revenue in the calculation of MDU's revenue requirements. Therefore, the gain on the sale of MDU's Bridger Office Building must be included as revenues in this proceeding. This decision requires an adjustment to increase revenues by $29,453.

Total Pro Forma Revenues

The Company asserted numerous times during this proceeding that volumes for interruptible sales and transportation services are dependent on the price and availability of substitute fuels. The Commission explicitly recognized this fact when flexible pricing was initially approved in Docket No. 87.12.77 (Order No. 5379) and again in this Docket when flexible pricing was allowed to continue. In adopting representative volumes for interruptible services, the Commission took great care to allow the Company a reasonable opportunity to fully recover its costs.

However, evidence in this Docket suggests that the representative volumes approved by the Commission may in fact be understated (FOF 33-34). While the Commission believes that the volumes approved in this Order may be understated, there is not enough information on the record to make such a conclusion.
Therefore, as a safeguard, the Commission requires MDU to file monthly reports for all interruptible sales and transportation services. The format of these reports must be consistent with the transportation reports required by Order No. 5379. To lessen the burdens associated with these reporting requirements, MDU will be allowed on a prospective basis to submit the reports quarterly. However, The Company is hereby required to report within one month such volumes and revenues that it has experienced from the time that flexible rates were approved to the current date.

In this proceeding, and MDU's last general electric proceeding, Docket No. 86.5.28, the Commission became aware that MDU does not report all revenues generated through the tariffed rates approved by this Commission. An example is late payment charge revenues. In an effort to ensure that all revenues generated by Commission approved tariffs are given due consideration in the ratemaking process, MDU will be required to include in all succeeding cases, gas and electric, a schedule showing all Commission approved charges and the corresponding revenues generated by each charge during the test year.

The Company reported $48,540,092 in actual total revenues during the test year. The Commission accepted numerous revenue adjustments, the total of which represent decreases in revenues of $1,475,756. The resulting pro forma revenue level accepted by the Commission is

$47,064,336.

III. EXPENSES

Uncontested Expense Adjustments

MDU and MCC agree on several expense adjustments in this proceeding. The following adjustments were proposed by both parties:

Operation & Maintenance	
Fringe Benefits	$ 7,653
Eliminate Advertising	(70,587)
Palm Springs Directors Meeting	(828)
Industry Association Dues	(13,655)
Postage Expense	19,614
Depreciation	
Average Depreciation	(27,512)
Depreciation on Completed CWIP not Booked	3,491
Taxes Other than Income	
Ad Valorem Taxes	1,989
Payroll Taxes	24,472
Current Income Taxes	
Tax Additions and Deductions	56,075
Eliminate Prior Year Rounding	(30,467)
New Tax Law	154,784
Energy Share Credit	(10,810)
State Income Taxes	68,372
Remove Conservation Loan Credit	82,170
Deferred Income Taxes	
Bad Debt	(40,828)
Eliminate Prior Years Rounding	(13,347)
New Tax Law	(72,821)
Investment Tax Credits	
Eliminate Investment Tax Credits (ITCs)	(29,170)
Eliminate Amortization of ITCs	495

These proposed adjustments appear to be consistent with past Commission decisions and are acceptable for purposes of this proceeding. Therefore, these adjustments are accepted at the levels proposed by the parties.

NSF Check Charge

As discussed in the revenue section of this Order, an expense adjustment must be made to reflect the Commission's decision regarding impacts of the NSF check charge. Pursuant to the Commission's decision on this issue, an $1,257 expense decrease must be recognized.

Labor Adjustment

Mr. Ball proposed an adjustment to increase labor expenses by $194,573. The Company's proposal used annualized wage levels as of November 3, 1989. To the annualized wage levels the Company added wage increases that would occur within 12 months of the test year. Finally, the Company multiplied this figure by a ratio of average test year employees to November 3, 1989 employees so that the adjustment would reflect the average test year number of employees.

Mr. Clark followed essentially the same methodology as Mr. Ball to calculate MCC's proposed adjustment to increase labor expenses by $120,612. However, Mr. Clark claimed that the Company's proposed adjustment contained an inconsistency in the manner in which it tied back to the test year number of employees. His proposed adjustment differs in that he uses a ratio of average test year employees to end of test year employees.

The Commission finds that the Company's proposed adjustment more accurately ties the adjustment back to the average number of test year employees. The ratio used by Mr. Clark effectively understates the average test year number of employees.
Therefore, the adjustment proposed by MDU is accepted. In making this finding the Commission is not saying that MDU's method is the only acceptable means of determining labor expense adjustments. Rather, the Commission is accepting MDU's adjustment because it more correctly represents current wages for the average number of test year employees than does MCC's. If MCC believes MDU's method is inappropriate, the Commission encourages MCC to develop a better method of recognizing current wage levels based on the average number of test year employees for use in the next MDU general rate filing. This Commission decision results in a $194,573 expense increase for purposes of this proceeding.

Rate Case Expenses

MDU and MCC proposed the same level of rate case expenses, $105,000, for purposes of this proceeding. Several years ago, the Company adopted an accounting procedure that recognizes previously authorized rate case expense levels for book purposes. Because of this procedure, an adjustment must be made to balance per books rate case expense with the amount experienced in this proceeding.

In the Commission's Interim Order, rate case expenses were allowed at the level experienced by MDU during the Company's last natural gas general rate filing, Docket No. 85.7.30.

In so doing, the Commission stated:

The Company may well incur more than $77,704 in rate case expenses for Docket No. 88.11.53 and will be required to report its actual rate case expenses at the conclusion of this proceeding for consideration in the Final Order (Interim Order No. 5399).

On November 20, 1989 the Commission received from MDU a letter reporting actual rate case expenses as of November 1, 1989. Based on the finding in Interim Order No. 5399 and the corresponding information filed by MDU, the Commission finds that MDU is entitled to recognition of $90,000 in rate case expenses which must be amortized over a two year period. After entering this figure into the procedure used by the Company to recognize rate case expenses, the Commission finds a $21,707 expense decrease is appropriate for purposes of this proceeding.

Loss Factor & Cost of Gas Adjustment

The Company proposed that a 1.19 percent loss factor be used in the calculation of gas costs. In his Direct Testimony, Mr. Ball referred to this proposed loss factor as "the average of the losses experienced during the test year" (MDU Exh. H, p. 10).

In actuality, MDU's proposed 1.19 percent loss factor is calculated by using 12 consecutive 12 month periods through the end of the test year. In other words, the Company proposes in its calculation to use the losses experienced from; August, 1986 through July, 1987, September, 1986 through August, 1987, October, 1986 through September, 1987, November, 1986 through October, 1987, December, 1986 through November, 1987, January, 1987 through December, 1987, February, 1987 through January, 1988, March, 1987 through February, 1988, April, 1987 through March, 1988, May, 1987 through April, 1988, June, 1987 through May, 1988, and July, 1987 through June, 1988 (MCC Exh. 1, MDU Response to MCC 1-34).

MCC witness Mr. Clark proposed that the 1.09 percent losses experienced during the 12 month period from January through December, 1988 be used to establish the appropriate loss factor for this proceeding. Mr. Clark reasoned that the calendar year 1988 data is more recent and better reflects the ongoing improvement in the loss factor resulting from the Billings main improvement program and the Company's accounting refinements (MCC Exh. 10, p. 16).

As reiterated by Mr. Clark (MCC Exh. 10, p. 16), the Commission is concerned that an approved loss factor be both accurate and reasonable. The difference between the Parties' proposed loss factors in this proceeding is small.

The Commission believes a method that smooths out irregularities and does not depend on a specific point in time measurement would be helpful in selecting an appropriate loss factor. Under cross-examination, Mr. Ball inferred that the Company's proposal encompasses these characteristics (TR p. 118). However, complete analysis of the method used by MDU to compute its proposed loss factor shows the opposite to be true.

The Commission examined the number of times each individual month's losses are counted in MDU's loss factor computations.

For instance, losses for the months of August, 1986, and June, 1988, are counted only once in MDU's calculations while the losses for the month of July, 1987, are counted 12 times. Under the Company's method, the loss factor is more than 79 percent dependent on the 13 months of losses from January, 1987 through January, 1988. Clearly, the Company's proposal does depend on a specific point in time measurement and cannot smooth out irregularities experienced during that critical 13 month period.

In the Interim Order for this proceeding, the Commission expressed concerns that the gas loss factor reflect decreased losses that should accompany the significant distribution plant investments made by MDU since its last general rate filing (Interim Order No. 5399). The Company's heavy reliance on January, 1987, through January, 1988, losses cannot reasonably reflect the decrease in MDU's loss factor because the Billings Main Improvement Program was still under construction during that period. Additionally, MDU's proposal uses loss data from as far back as August, 1986, further compounding this problem.

During the hearing, Mr. Ball discussed certain accounting refinements implemented by the Company to make its monthly gas loss measurements more precise (TR pp. 81-82). The Commission finds it likely that the August, 1986 through June, 1988 time period used in MDU's gas loss calculations does not totally reflect implementation of these accounting refinements. This means that MDU's proposed loss factor is at least partially based on less precise measurements than is MCC's.

While the 1.09 percent loss factor proposed by Mr. Clark also does not smooth out irregularities and also depends on a specific point in time measurement, the Commission finds the MCC proposal to be more acceptable than the MDU proposal. By examining losses through December, 1988, Mr. Clark's proposal better matches the loss factor with the increased distribution investments now carried in rate base. Also, his proposal is less likely than the Company's to be contaminated by imprecise data. The Commission finds that 1.09 percent is an appropriate gas loss factor for purposes of this proceeding. Based on this factor, and the sales volumes discussed previously in this Order, the Commission determines that pro forma gas costs must be reduced by $3,182,412. Additionally, the Commission would like both parties to address in MDU's next filing the merits of a method to determine a loss factor that smooths out irregularities and does not depend on a specific point in time measurement.

Pro Forma Interest

The Company calculated its proposed pro forma interest adjustment on a total company basis and then allocated the interest expense to the state jurisdictions based on net plant in service.

Mr. Clark testified on behalf of MCC that the Company's method is unfair to Montana ratepayers because it does not fully reflect the interest expense associated with construction occurring in the Montana jurisdiction. He stated that the calculation should be made on a jurisdictional basis by using the Montana specific rate base and Montana specific Construction Work In Progress (CWIP) (MCC Exh. 10, pp. 9-10).

The Commission agrees with Mr. Clark. The Company's proposed method of calculating pro forma interest expenses does not fully recognize, in the determination of Montana revenue requirements, interest expenses associated with construction occurring in this jurisdiction.

Changes in pro forma interest expense cause a change in state and federal income taxes due to the deductibility of interest. Using the accepted rate base, debt percentage of the capital structure, MDU's weighted cost of debt, and the MCC proposed method of calculating pro forma interest, the Commission finds an adjustment to reduce state and federal income taxes by $10,076 is appropriate.

Divisional Consolidations

In his direct testimony, Joe Maichel stated:

> Also, realignment within divi sions/districts has been reviewed and is ongoing. The consolidation of the Wolf Point and Williston divisions is an example of this effort which has resulted in reduced expenses (MDU Exh. A).

In response to PSC-13, MDU reported that the Wolf Point - Williston savings were not reflected in the Company's filing, but the expenses to perform this consolidation were.
Also, the Company revealed that the Billings and Sheridan Divisions would soon be consolidated, and that substantial savings would be realized from this consolidation as well (MDU Responses to PSC-13, PSC 226, and PSC-227). The Company also reported that the Billings - Sheridan consolidation would take place July 1, 1989, exactly 12 months plus one day past the end of the test year.

MCC witness Clark failed to address this issue in his direct testimony, but in response to a data request, did comment:

If the $144,000 can be substantiated as a known and measurable change occurring within twelve months after the close of the test year and it is a recurring savings, it should be reflected in the revenue requirement. Proper allocation to Montana gas operations would be required.

The Commission agrees with Clark that the savings should be reflected if the values can be demonstrated to be known, measurable and recurring.

The Company's responses to data requests (PSC-225 through PSC-227), and questions posed during the hearing (TR pp. 40-41, 44-45, 109-116, and 157-158) clearly demonstrate that the savings are known, measurable, and recurring. Without hesitation, the Commission finds that the savings associated with the Wolf Point - Williston consolidation must be reflected in this proceeding. The savings resulting from the Billings - Sheridan consolidation, however, require substantially more consideration.

Commission Rule ARM 38.5.106 states in part: "No adjustment will be entertained unless it will become effective within 12 months of the last month of the test period as used in this section." Strict adherence to the Commission's 12 month rule would exclude the Billings-Sheridan consolidation savings from being considered in this Docket. In this Docket, the Commission has determined that for the Billings-Sheridan consolidation, adherence to Rule 38.5.106 is appropriate. The parties in this proceeding filed their cases based in part on their reliance on Rule 38.5.106. The Commission did not find the evidence relating to the Billings-Sheridan consolidation compelling enough to justify waiving Rule 38.5.106.

The Commission is interested in the issues which underlie the application of Rule 38.5.106. Should the Commission adhere to a strict application of Rule 38.5.106? If there are reasons to deviate from the Rule, what are they? Should the Commission modify this Rule? Both MDU and MCC are invited to share their views with the Commission in the next general rate case for MDU.

Based on its analysis of information contained in the record of this proceeding, the Commission finds that the Billings-Sheridan consolidation savings should not be reflected. Therefore, recognition of the Wolf Point-Williston consolidation requires reflection of an expense decrease totalling $43,845.

Injuries and Damages Expenses

MDU commonly includes adjustments to insurance expenses in its filings. In this Docket, neither the Company nor MCC proposed such an adjustment.

Insurance premiums are expensed by MDU over a 12 month period in Account No. 925, Injuries and Damages Expenses. Most of MDU's insurance premiums are paid in November each year and are then expensed over the following 12 month period (MDU Response to PSC-229). The majority of costs expensed to Account No. 925 represent liability insurance, workers compensation insurance, and the self insured portion of the Company's general liability insurance (MDU Response to PSC-228). A review of the Company's O&M expense reports revealed that General Office Account No. 925 expenses have been consistently decreasing over the last several years:

12 Months Ended	Expenses Reported
June 1987	$ 1,130,114 **
June 1988 (test year)	727,477 **
Dec. 1988	636,033 **
April 1989	570,756 **

** Montana's allocated portion can be obtained by multiplying the numbers by approximately 34%.

MDU provided three main reasons for decreases in this expense account:

1. In total, insurance premiums have declined every year after reaching a peak in November 1986.
2. There has been a shift in the allocator from gas to electric for general and excess liability expenses. The shift was due to a change in the historic amount of gas vs. electric claims.
3. Sometime during the 12 months ended June 1987, the Company booked a significant increase in the provision for self insured general liability losses. In succeeding periods MDU has been making net decreases to this provision. This provision is recognized to expenses through a 12 month amortization procedure. (MDU Response to PSC-228 and TR pp. 64-69)

Several facts are known about the test year level of general office expenses recorded in Account No. 925. The test year expenses contain four months of expenses for the "peak" November, 1986 insurance premiums and 8 months of expenses for the November, 1987 insurance premiums (MDU Response to PSC-228 and TR pp. 64-69). None of the November, 1988 insurance premium decreases are included in the test year (supra). The test year may contain several months of higher expenses resulting from the significant increase in the provision for self-insured general liability losses that was booked some time during the 12 months ended June, 1987. Some portion of those expenses will appear in the test year due to the 12 month amortization of this provision (supra), and probably does not reflect the full amount of all succeeding decreases to this provision (supra). The test year does not fully reflect the change in the gas/electric allocator for general and excess liability expenses (supra).

The Commission determines the test year level of expenses to be overstated and unusable for the purposes of this proceeding. Rather, the Commission finds the expenses recorded for the 12 months ended April, 1989, should be reflected.

Use of the expenses recorded for the 12 months ended April, 1989, will not cure all of the problems found by the Commission, but it does allow for some recognition of the November, 1988 insurance premium decrease (6 months), it eliminates the effects of the increase in the provision for self-insured general liability losses, it allows for some of the succeeding period's decreases in this provision to be recognized, and it allows for better recognition of the change in the gas/electric allocator for general and excess liability. Therefore, the Commission finds it reasonable to reflect an expense decrease of $53,285 for purposes of this proceeding.

PSC and MCC Taxes

Both parties proposed adjustments to reflect the effects pro forma revenue adjustments have on the levels of PSC and MCC tax expenses. Based on the accepted pro forma revenue levels and the tax rates applicable at the close of the hearing, the Commission determines that a $0 adjustment to MCC tax expenses and $5,889 decrease to PSC tax expenses is required.

Total Pro Forma Expenses

The Company reported $47,882,854 in actual total expenses during the test year. The Commission accepted numerous expense adjustments, the total of which represent decreases in expenses of $2,360,582. The resulting pro forma level of expenses accepted by the Commission are $45,522,272.

IV. RATE BASE

Uncontested Rate Base Adjustments

The two parties proposed several identical rate base adjustments. During the hearing, MDU agreed to the treatment proposed by MCC for Conservation Loan Balances (TR p. 73). The agreed upon rate base adjustments are:

Accum. Depr. on Completed CWIP not Booked	1,755
Materials & Supplies	(35,232)
Prepaid Insurance	14,539
Unamortized (Gain)/Loss on Debt	161,355
TRA Deferred Taxes	6,766
Bad Debt	(107,465)
Conservation Loan Balances	0

These proposed adjustments appear to be consistent with prior Commission decisions and are reasonable for purposes of this proceeding. Therefore the adjustments are accepted at the levels proposed by both parties.

Average Depreciation Reserve

When an adjustment is made to depreciation expense, it is proper from a matching perspective to make a corresponding adjustment to the depreciation reserve in rate base. Neither MDU nor MCC proposed a corresponding depreciation reserve adjustment when each proposed an adjustment to reflect average depreciation expenses. The Commission has customarily required that this matching adjustment be made and continues in this proceeding to find an adjustment to be appropriate. Proper matching requires recognition of an adjustment to increase rate base by $13,756.

Prepaid Demand Charges

The Company proposed an adjustment to increase its rate base by $390,060 to fully reflect prepaid demand charges.

MDU included a 13-month average balance of prepaid demand charges in its proposed rate base. During the hearing, Mr. Ball corrected a minor error in the Company's proposal, resulting in a change in MDU's proposed rate base adjustment from $390,060 to $387,077 (TR p. 229).

The Company views the average balance of prepaid demand charges to be an investment which is required to serve its customers; thus, it should be included in rate base. Mr. Ball stated that MDU has been paying the demand charges since May of 1986, so the prepayments are properly amortized over the 12 months ending in April. He stated that changing the amortization period to a different cycle would cause a one-time charge to the cost of gas of approximately $.08/dk.

MCC proposed a $442,640 rate base decrease to remove all prepaid demand charges from rate base. Clark claimed that "prepaid demand charges" is a misnomer. He stated that there are some months that the demand charge is prepaid and some months that it is postpaid. Clark constructed a scenario showing that this issue would result in a significant rate base reduction based on a calendar year cycle rather than the twelve months ending in April. He further stated that similar analyses for other 12 month cycles would show the pre and post payments are essentially equal. Thus, he concluded that rate base treatment is not warranted (MCC Exh. 10, pp. 28-29).

Under cross-examination, Mr. Clark discussed the fact that MDU is making the prepayments to Williston Basin Interstate Pipeline (WBIP), an affiliate that is 100 percent owned by MDU Resources which is also MDU's parent company. Mr. Clark claims that since the demand charges are being made to an affiliate and the affiliate has no rate base offset to recognize the prepayment, rate base treatment is not warranted because the funds are still available for MDU's stockholders to earn a return through the affiliate. Mr. Clark concluded that the stockholders of MDU Resources would earn a return twice on prepaid demand charges if the Commission allows rate base treatment of this item (TR pp. 216-218).

The Commission believes this double recovery argument may have merit, but finds it to be more appropriately addressed by the Federal Energy Regulatory Commission (FERC). It is the desire of this Commission to establish rates which will give MDU an opportunity to recover prudently incurred costs, including a reasonable return on investments. To not recognize the prepaid demand charge balances could leave MDU in a situation where it will not recover costs which the Company cannot avoid. The Commission may pursue the double recovery issue before the FERC in an appropriate WBIP proceeding. MDU should not be punished for omissions or errors on the part of the FERC.

The Commission urges the MCC to pursue this issue before the FERC in order to prevent any future double recovery from Montana ratepayers.

MDU pays demand charges to Williston Basin in equal monthly amounts. The prepaid demand charge balances result from a levelization procedure used by the Company to stabilize its monthly recorded average cost of gas. Stabilizing the recorded cost of gas helps to minimize the magnitude of summer/winter gas tracker rate changes.

Mr. Ball testified that MDU and its customers have both benefited from stable gas prices brought about by the levelization procedure (MDU Exh. H, p. 16). The Commission agrees.

Mr. Ball further testified that Mr. Clark's proposal fails to recognize that changing the amortization period to achieve a zero balance would cause a one-time $.08/dk charge to be incurred by MDU's customers.

The Commission agrees with MDU that, from an accounting perspective, Clark's analysis of this issue is in error. As demonstrated by MDU, a one-time $.08/dk charge would be required to achieve a zero average balance in prepaid demand charges.
That charge would not be insignificant.

The Commission finds that the 13-month average balance of MDU's prepaid demand charges should be allowed in rate base.
This decision warrants an adjustment that increases rate base by $387,077.

Construction Overheads

Mr. Clark proposed a $291,459 rate base decrease to restate capitalized construction overheads to the level resulting from the rates approved in Docket No. 85.7.30. This adjustment was made by the Commission in the Interim Order in the current Docket. Mr. Clark stated in direct testimony:

I support the Commission's interim adjustment on a permanent basis because the Company was very clearly told what the acceptable overhead rates were for Montana ratemaking. To allow MDU to ignore the Commission's order in Docket No. 85.7.30 would be totally wrong, would seriously undermine the regulatory control of this Commission and would constitute retroactive ratemaking.

(MCC Exh. 10, p. 21)

In his direct testimony, Mr. Clark appeared to indicate that the Commission should continue to approve overheadrates and also appeared to recommend that the rates shown in Statement C be approved for ratemaking in this Docket (MCC Exh. 10, pp. 23-24). During cross-examination, Mr. Clark was asked if his position was that the Commission should mandate construction overhead rates for ratemaking purposes. He responded that this was not his position and that he has not recommended it in this proceeding (TR p. 211).

Mr. Ball of MDU disagreed with Mr. Clark's proposal because it is in conflict with the requirements of the Uniform System of Accounts (USOA). The USOA requires that payroll charges includable in the overhead rates must be based on time card distributions or special studies. Mr. Ball stated that Commission specified overhead rates violate USOA requirements because they become arbitrary through the passage of time and because they represent assumed overhead costs (MDU Exh. H, pp. 10-11).
He recommended that the Commission not approve specific overhead rates. Rather, Mr. Ball stated that the Company's overhead rates should be allowed to change when conditions necessitate, as long as they are in compliance with the USOA. Mr. Ball further stated that if specific overhead rates are established by the Commission, then MDU would be required to maintain two sets of records. He concluded that this would complicate future rate proceedings and cause additional costs to maintain separate books for ratemaking and accounting (MDU Exh. H, pp. 13-14).

The Commission agrees with Mr. Clark; the USOA is a guide for accounting and does not control ratemaking (TR p. 209). If it did, the Company's revenue requirements could easily be determined with an accounting manual, which would require little or no reasoning on the part of this Commission.

The Commission senses some confusion of this issue. Therefore the Commission will review the history of this matter.

In Docket No. 85.7.30, MCC witness Clark testified that MDU's construction overhead rates had been increasing at an unwarranted rate. MDU's witness Mr. Ball could not justify the increases when asked to do so at the hearing. The record developed in Docket No. 85.7.30 caused the Commission to seriously question the overhead rates being used by MDU. The Commission wanted MDU to fully address this issue in its next case and, as a signal to the Company, made an adjustment to remove from rate base a minor amount of construction overheads.

In the current Docket, MDU failed in its original filing to address this issue. The Commission's procedural order required the Company to submit supplemental testimony addressing construction overhead rates used by MDU since January 1, 1985. As an even stronger signal than was sent in Docket No. 85.7.30, the Commission recalculated all construction overheads since January 1, 1985, and removed $291,459 from rate base in the Interim Order.

Mr. Ball addressed the construction overhead issue in supplemental testimony. Mr. Ball explained that on July 1, 1986 (shortly after the Final Order was issued in Docket No. 85.7.30), MDU significantly changed its construction overhead procedures. Prior to July 1, 1986, the Company reviewed its construction overhead rates about every three years. Reviews have been conducted annually since that time. The shorter period was required to better control costs that were being capitalized as construction overheads.

Mr. Ball further testified that the new procedures have resulted in lower construction overhead rates than were seen in Docket No. 85.7.30. As evidence of this statement, Mr. Ball included with his supplemental testimony a schedule of construction overhead rates used by the Company since January 1, 1985.

The Commission reviewed the schedule provided by Mr. Ball and finds that the Company has, in fact, brought its construction overhead rates in line. The Commission is pleased that MDU did not ignore the concerns expressed in Order No. 5160a.

No party in this proceeding is proposing that the Commission mandate specific construction overhead rates. The Commission agrees. There is no need at this time to mandate overhead rates that are different than those used by the Company on a per books basis.

This leaves to be resolved construction overheads booked since Docket No. 85.7.30. When Order No. 5160a was issued, the Commission was concerned that MDU not be permitted to recover its costs twice: once through the per books levels of expenses; and again by later increasing the overhead rates and capitalizing costs that had been recognized as expenses in Docket No. 85.7.30. Mr. Clark interpreted the Commission's Order as a mandate of specific overhead rates. That was not the intent of the Commission when issuing Order No. 5160a.

Mr. Clark was asked about the mechanics associated with changes in the overhead rates. He responded:

If one assumes a perfect match in a test year, and that all costs incurred are to be recovered from ratepayers, then if the capitalized portion of the allowed costs are altered, the expensed portion of the costs would change by a like amount in the opposite direction. This in no way means that one should allow the recovery of prior year expenses that were erroneously capitalized.

(MCC Response to PSC-124)

In response to PSC-28, the Company provided a schedule of construction overhead rates used from 1978 through 1984. That response, and Mr. Ball's supplemental schedule, show that MDU used the "high" overhead rates from January, 1984 through the end of June, 1986. The Commission is satisfied that MDU hasnot attempted to recover its costs twice. That fact is clear because MDU used the "high" construction overhead rates during the entire Docket No. 85.7.30 test year and did not increase the overhead rates above that test year level.

The Commission concludes that Mr. Clark's proposal would unfairly penalize the Company. Therefore, no adjustments are warranted for this issue.

Total Pro Forma Rate Base

The Company reported $16,494,912 in actual total rate base during the test year. The

Commission accepted several rate base adjustments, the total of which represents an increase in rate base of $439,041. The resulting pro forma level of rate base accepted by the Commission is $16,933,953.

V. AMORTIZATION OF PRE-1974 GAIN ON REACQUIRED DEBT

Consistent with prior Commission decisions, both parties proposed a $14,000 increase in operating income be made to reflect the previously ordered amortization of pre-1974 gains on reacquired debt. Consistent with previous decisions, the Commission accepts the $14,000 adjustment.

VI. REVENUE REQUIREMENTS

Based on all accepted adjustments to the per books level of rate base, revenues and expenses, and the approved cost of capital in this proceeding, the Commission finds that MDU is entitled to an increase in revenues of $452,636. This increase is in lieu of, not in addition to, the $411,924 interim increase granted on February 15, 1989. The schedule on the following page shows the revenue requirement calculation.

(Please see schedule in original Order)

PART 4

COST OF SERVICE

I. ORGANIZATION AND BACKGROUND

This part of the order addresses the various costing and pricing issues raised by parties in the docket. This part is divided into the following sections. This section reviews the order's organization and provides the historical background leading up to the present docket. Section II briefly describes the cost of service (COS) and rate design (RD) model used to organize the parties' testimony and the Commission's decision.

Sections III and IV summarize MDU's and MCC's COS and RD testimony, respectively. The next section contains the Commission's COS decision. Tables describing the parties' COS methods and results are included in Technical Appendix C. This appendix also includes tables that describe the Commission's COS decisions. Following a discussion on moderated revenue requirements, the order, in turn, reviews MDU and MCC's RD proposals and the Commission's RD decisions.

Several MDU dockets provide much of the background for COS and RD issues in the present docket. First, in Docket No. 85.7.30, MDU filed embedded and marginal COS studies. MDU maintained in that Docket that marginal COS study results are useful in that they support embedded costs (Order No. 5160a, FOF 133). Also in that Docket MDU based RD proposals, in part, on embedded class rates of return (Id., FOF 121-122). The Commission found that marginal costs should serve as the primary basis for setting efficient prices.

Second, in Docket No. 87.12.77, the Commission addressed MDU's request to flexibly price interruptible sales and transportation Rates 81, 82 and 90. In Docket No. 87.12.77, the Commission required MDU (Order No. 5379) to file a long-run marginal cost (LRMC) study in support of its flexibly priced interruptible sales and transportation services. Third, in ongoing Docket No. 88.8.23, MDU proposed significant RD changes that, to some extent, overlap with proposals in the present docket.

II. GENERAL COST OF SERVICE AND RATE DESIGN MODEL

Table 1 provides an outline of the logical model of cost of service studies the Commission applies in this Order. This model, which results in final prices, is reviewed in more detail below. In the context of this order the COS/RD model is used not only as a means to develop prices from costs but also to provide the reader a road map to aid in understanding the Commission's decisions regarding COS and RD.

TABLE 1

GENERAL COST OF SERVICE AND RATE DESIGN MODEL

	Costing		Pricing/	
Function	Classified	Allocated	Reconciled	Rate Design
(1)	(2)	(3)	(4)	(5)
Production	Energy,	Seasons,	Uniform	$per/dk:
Distribution	Demand,	Peak Days,	Percent or	
Transmission	Customer	Customer	Other e.g.,	$/mo/cust:
		Classes	Market Based	

Using this model, costs are first functionalized. In the instant docket, only three functions arise. Functionalized costs are then classified as either energy, demand (capacity) or customer (access) related. Classified costs are later allocated to seasons, peak days, or customer classes.

Since marginal cost revenue requirements normally do not equal the allowed revenue requirement, costs must be reconciled to allowed revenues. A uniform percent adjustment or Ramsey pricing are two reconciliation methods. Once costs and revenues are reconciled, prices must be computed. Gas pricing usually involves a two-part tariff consisting of energy prices and Base Rates.

III. MDU'S COST OF SERVICE: DOCKET NO. 88.11.53

Mr. Russell Feingold and Mr. Donald Ball testified on MDU's behalf on marginal and embedded COS study results, respectively. MDU's initial filing provides marginal and embedded COS analyses for its Residential and firm commercial classes (Exh. Nos. MDU-C and MDU-I and Statement M). MDU analyzed embedded costs for interruptible sales and interruptible and firm transportation rates (Exh. No. MDU-C, DRB-4). In compliance with Order No. 5379 in Docket

No. 87.12.77, MDU later filed additional marginal cost analyses for Rates 81, 82 and 90 (Exh. No. MDU-J). This analyses was included in Mr. Feingold's Supplemental testimony. In addition to calculating long-run marginal costs for Rate 81, 82 and 90 customers, MDU also revised its initially filed marginal COS study. The following reviews Mr. Feingold's direct and Supplemental COS testimony.

MDU's Cost of Service Perspectives

Theoretically, MDU defines marginal costs as the change in costs due to a change in the level of service provided and states that marginal costs may be the increment or decrement in cost associated with increasing or decreasing service (MDU Exh. I, p. 6). MDU maintains that a marginal cost study serves to aid in determining class revenues and prices derived from an embedded COS study. MDU also maintains that marginal costs establish a "minimum rate level that a local distribution company (LDC) should charge for utility service" (Id., p. 17). In this regard, MDU supports using short-run marginal costs (SRMCs), excluding gas costs, to evaluate price floors for transportation service.

Functionalized and Classified Costs

The discussion of functional and classified costs is divided into two parts, to reflect MDU's testimony. The first part regards Rates 60 and 70. The second part regards all flexibly priced tariffs. Using the model in Table 1, MDU functionalizes marginal costs as production, demand or customer related. Table C1 summarizes the results of MDU's functionalization and classification of firm sales customers' (Rates 60 and 70) costs. Additional detail on how MDU computes and classifies the costs functionalized in Table C1 will follow.

Energy. Actually termed "production" MDU defined its marginal gas energy cost as the price MDU paid for gas from swing or incremental gas suppliers (MDU Exh. I, p. 7). MDU maintains that since gas purchased from lower cost supplies constitutes base loads for firm customers, incremental gas supplies will be composed of purchases from WBIP (Exh. No. MDU-I, p. 8).

Therefore, MDU bases its marginal gas and nongas energy costs on WBIP's G-1 tariff (Id.).

MDU adjusts these costs upward to account for a 1.19 percent gas line loss factor for its distribution system. Since WBIP's energy costs are not seasonally differentiated, MDU's marginal gas costs do not vary by season.

Mr. Feingold's Supplemental testimony (Exh. No. MDU - J, Exh. RAF-12) updated MDU's marginal gas cost to $2.444 per dk.

Although not reflected in its COS analysis, MDU has begun taking gas from alternative suppliers due to WBIP's open access status. MDU expects to acquire alternative supplies at lower prices at least in the short-run. As of January 1, 1989, MDU converted 15 percent of its Annual Entitlement Quantity (AEQ) to Annual Delivery Quantities (ADQs) and 5.4 percent of its Maximum Daily Quantity (MDQ) to Maximum Daily Delivery Quantities (MDDQ). MDU pays its alternate supplier $1.45 per dk during 1989, and subsequent year's prices will be negotiated (MDU response to PSC DR No. 31 a). MDU plans to take these lower cost supplies at or as close to a 100 percent load factor as possible, and refers to these lower cost supplies as base load supplies. The significance of the discussion in this finding is discussed in the Rate Design section of the Order.

WBIP's G-1 tariff also includes MDQ and AEQ demand charges. MDU maintains, however, that MDQ and AEQ charges do not change as MDU receives more or less volumes from WBIP (Id., p. 9). According to MDU, however, changes in the level of gas cost due to changes in volumes received are directly related to the G-1 commodity charges (Id.).

Demand. MDU only computes one type of marginal demand cost, which is the marginal cost of distribution capacity.

MDU developed distribution demand costs as follows. First, MDU identified investments made during the period of 1984 through June 30, 1988 associated with additional gas volumes. Replacement investments were excluded in this study. In order to smooth out lumpy changes in marginal demand costs, MDU averaged capacity expansion investments over the time period stated above. MDU restated annual investments on a constant dollar basis and divided the sum of these investments by the sum of increases in design peak (Id., p. 11).

To the above marginal investment cost estimate MDU proposed numerous cost adders, including a 9.543 percent general plant allocation factor. A nominal 17.59 percent carrying charge was applied to incremental investments adjusted for general plant to generate annual carrying costs. Additional annual costs associated with supporting, operating, and maintaining the investments were applied to the marginal demand carrying charge. These costs include operation and maintenance (O&M) expenses, administrative and general (A&G) expenses and working capital (Id., pp. 13-14). The end result of the above analysis is the $11.45/peak day Mcf, noted in Table C1.

Customer. MDU developed functionalized marginal customer costs for firm residential (Rate 60) and commercial (Rate 70) classes. MDU defines marginal customer costs as the cost incurred to connect a new customer to its gas system. Although not termed a "replacement cost" approach, that is the essence of MDU's analysis. MDU states these costs reflect the minimum costs it incurs to connect a customer (Exh. No. RAF-7, p. 2).

Some technical detail on MDU's customer costs follows. MDU computed class marginal customer costs using a 9.453 percent general plant factor and a 17.59 percent nominal carrying charge to arrive at an annual carrying cost (Id., p. 15 and RAF-7, p. 1). MDU added O&M, A&G, and working capital costs to its carrying cost. The end results of this analysis are the annual customer costs outlined in Table C1.

Cost Allocation and Reconciliation

Table C2 summarizes how MDU allocated costs to classes (Exh. No. MDU-I, RAF-10). Unit costs are multiplied by billing determinants to compute total class marginal costs. MDU then used an equal-percent method to reconcile marginal costs with the embedded revenue requirement.

MDU's Rate 71, 81, 82, 85 and 90 Cost of Service

The following is a discussion of Rates 71, 81, 82, 85 and 90. Rate 71 is MDU's interruptible commercial gas sales tariff. Rates 81 and 82 are MDU's interruptible transportation tariffs. Rate 81 pertains to those customers qualifying for service under Rate 71, where Rate 82 pertains to those customers qualifying for service under Rate 85. Rate 85 is MDU's interruptible sales tariff for industrial customers. Rate 90 is MDU's alternative fuels tariff established for its interruptible customers with interruptible alternate fuel burning equipment.

Out of Order No. 5379 (Docket 87.12.77) MDU was required to file long-run marginal cost studies for certain tariffs. If MDU had failed to file COS studies for Rates 81, 82 and 90, and should a proceeding addressing such cost studies not be completed within 15 months after the approval of flexible rates in Docket No. 88.12.77, MDU's Rates 81, 82 and 90 would be priced at the last tariffed margin based prices (Order No. 5379, FOF 51). In its order, the Commission advised MDU to address the following cost concerns: 1) costs disaggregated by customer level; 2) transactions costs incurred to provide transportation service; 3) costs for interruptible, retention and standby services.

Functionalized and Classified Costs

As noted earlier, MDU filed supplemental marginal COS testimony for flexibly-priced tariffs (Rates 81, 82 and 90). Additionally, MDU filed COS testimony for Rates 71 and 85.

MDU also noted that it made some cost classification adjustments to its A&G and customer related O&M cost adders (Exh. No. MDU-J, pp. 5-6 and 9). These adjustments have been reflected in Table C1.

Energy. MDU updated its marginal gas cost in Mr. Feingold's supplemental testimony, as noted earlier, and provided energy costs for each of its Rate 71, 81, 82, 85 and 90 customers (Exh. No. MDU-J, RAF-11). MDU's updated or marginal gas costs appear to use the same method used in its direct testimony.

Demand. Based on its cost analyses, MDU maintains that interruptible customers do not cause demand-related costs. MDU maintains that marginal demand costs are incurred to meet firm customers' increased peak day demands not interruptible customers' demands. An exception are dedicated customer facilities which are accounted for under marginal customer costs. MDU notes that interruptible service, by definition, is only provided when excess capacity exists. Furthermore, the Company notes that incremental capacity costs can be avoided by reducing service to interruptible customers. MDU maintains that the presence of interruptible customers benefit the system's firm gas customers and do not cause added capacity costs. Thus, MDU did not compute marginal demand costs for interruptible customers (Exh. No. MDU-J, pp. 6-8).

Customer. MDU computed marginal costs for its Rate 81, 82, and 90 customers using a method similar to that used for firm customers (Exh. No. MDU-I, RAF-7 and pp. 14-16 and Exh. No. MDU-J, RAF-17 and pp. 4-6). As required by Order No. 5379 (FOF 53), MDU computed customer specific marginal costs.

MDU computes marginal customer costs using the minimum investment required to connect each customer to its system.

Such costs vary by tariff and customer. For instance, MDU's proposed distribution level Rate 85 customer costs include: 1) installed costs of distribution mains, 2) service stub, and 3) structures, improvements and station equipment. Rate 85 transmission level customer costs includes 1) service stub for Cenex, and 2) structures, improvements and station equipment for Cenex, G. Energy and Holy Sugar. Only structures, improvements and station equipment are included for the Glendive Turbine, Lewis and Clark plant and Miles City Turbine, whereas distribution main, service stub, and meter and regulator compose the investment base for the remaining Rate 71 customers (Exh. No. MDU-J, RAF-17). The service stub is the portion of pipe connecting the customers service line to the distribution main.

MDU maintains that its LRMCs reasonably measure the marginal costs for interruptible customers. MDU also holds that the costs it computed can serve to establish marginal cost based floor prices for flexibly priced customers (Exh. No. MDU-J, p. 10).

Allocation, Reconciliation and Remaining Cost Considerations

MDU maintains it addressed the Commission's concern (Order Nos. 5379 and 5379a) that a customer could receive sales or transportation service from MDU at a flexibly adjusted price that exceeds the short-run incremental cost but which falls below the long-run marginal cost in conjunction with the fact MDU proposed no sunset. A sunset on flexible pricing could lead to a pricing strategy different than that applied under first-degree price discrimination. Under first-degree price discrimination the seller seeks to extract all of the purchasers willing-ness-to-pay for service. If a sunset were placed on flexibly priced rates the seller may be moved to cover only out-of-pocket expenses in its prices.

MDU proposed using the marginal costs developed for Rate 81, 82 and 90 customers as a basis for establishing unbundled floor prices where cost differentials exist. Mr. Feingold's proposal stems from the cost differences incurred to serve positive displacement and orifice metered customers, the latter of which are generally larger customers (Exh. No. MDU-J, pp.

10-12). MDU proposes that since the variation in costs for each of these two groups is relatively small, a single price floor based on the average of each customer's LRMC within the group would ensure that transportation service for these customers would be priced above long-run marginal costs. MDU adds that this floor should include gas losses.

MDU proposes that Rate 90 be handled similar to Rates 81 and 82 (Id.). The commodity price floor should be set no lower than the weighted average commodity cost of gas purchased by MDU (Id., p. 12). MDU also proposes that the floor include the relevant transportation floor price and applicable gas losses.

MDU contends that unbundled ceiling prices for Rates 81, 82 and 90 are unnecessary. MDU argues that with full margin based prices, first-degree price discrimination is nonexistent.

Hence, an evaluation of due or undue discrimination is not needed. Mr. Feingold concludes that "separate cost support...for purposes of evaluating and establishing floor prices within an environment of first-degree price discrimination is not needed when establishing ceiling prices" (Id., p. 13).

Because it believes seasonal cost variations for transportation services do not exist, MDU maintains that its updated marginal cost study does not support flexible price floors (Id., p. 14). Since MDU considers customer costs as the primary marginal cost for interruptible transportation customers, there are no seasonal costs.

With regard to transaction costs, Mr. Ball stated that MDU has not hired any additional staff to implement transportation services and flex-priced rates. Hence MDU, contends there are no incremental transactions costs to be incurred in the provision of transportation services or the administration of flexible rates" (Exh. No. MDU-G, pp. 4-5).

Additional Cost of Service Testimony

Standby Rate 83. In Order No. 5379 (FOF 72) the Commission stated that it would not entertain a refiling of Standby rates outside the context of a cost of service filing. Mr. Ball's direct testimony contains MDU's proposed Standby tariff.

Cost and pricing issues are deferred until the RD section of this order.

Rates 71, 85, 81, 82 and 84. In its initial filing, MDU provided embedded costs for Rates 71, 85, 81, 82 and 84 (Exh. No. MDU-C, pp. 31-35 and DRB-4). These costs were based on classified costs for Rates 60 and 70. Costs were unitized based on MDU's total firm dk sales. Demand costs for Rates 71, 85, 81 and 82 were based on Mr. Feingold's marginal demand cost at a 100 percent load factor. The demand cost for Rate 84 was based on the same marginal cost at a 35.9 percent commercial class load factor. Energy costs were broken into the cost of gas and other costs. The cost of gas was based on MDU's weighted cost of gas and included line losses at 1.19 percent. These costs are summarized on Table C3.

IV. INTERVENOR TESTIMONY: COST OF SERVICE

Although several parties intervened in this docket, only MCC filed testimony. Mr. Drzemiecki filed direct (Exh. No. MCC-12) and supplemental (Exh. No. MCC-13 and MCC-14) testimony on MCC's behalf. MCC's testimony covered COS and RD. MDU's rebuttal of MCC's testimony will be woven into the following summary as appropriate. Tables A4, A5 and A6 summarize MCC's COS and reconciliation proposals.

MCC Cost of Service / Rate Design Perspectives

MCC defines marginal costs as the cost of added service and adds that marginal cost based prices will encourage conservation, efficiency, and equity (Exh. No. MCC-12, pp. 14-18). MCC argues that prices must signal capacity costs to consumers to efficiently allocate resources (Exh. No. MCC-12, p. 16). MCC also maintains that LRMCs promote conservation, efficiency, and equity by reducing the possibility of inter-classcross subsidizations (Id., pp. 18-20).

Functionalized and Classified Costs

MCC functionalized costs as purchased gas, distribution, and customer related (Exh. No. MCC-12, JD-2, p. 1). The following summarizes MCC's COS analysis presented in direct and supplemental testimonies.

Production. MCC developed production costs, which it terms "purchased gas." MCC's purchased gas energy costs include two components: 1) unit marginal gas costs; and, 2) the capacity (demand) cost of firm transport. Each is discussed in turn. First, MCC maintains that purchased gas energy costs consist of the cost of acquiring gas from producers, brokers or pipelines. MCC adds that its calculations represent marginal gas supply costs associated with customer's existing and expanding gas loads and maintains that MDU will avoid these costs if loads are reduced. MCC actual marginal commodity costs use field acquisition and forecast data from sources other than WBIP (Exh. No. MCC-12, p. 31 and footnote 1 in JD-1, p. 4).

In supplemental testimony, MCC revised its gas cost analysis to include a forecast of gas supply costs (Exh. No. MCC-13, pp. 6-7). It appears MCC forecast two gas prices using a mix of WBIP and alternate gas sources (Exh. No. MCC 5-9, Att. A, p. 7 and MCC DR PSC-295-a). MCC uses the midpoint of these two forecast costs to compute gas costs through 1990 (Original and Amended Exh. No. MCC 9, Response No. MDU-18). MCC selected the mid-point of the range in order to reduce uncertainties associated with forecasts. Table C4 summarizes MCC's cost of gas as presented in its revised supplemental testimony (TR pp. 319-332, Exh. No. MCC-14, Exh. No. J.D.-7, p. 4).

Using this data MCC computed firm customers' gas costs by dividing the total cost of firm transport by firm transport volumes and adjusting for losses using MDU's proposed 1.19 percent loss factor. Interruptible gas costs were computed by dividing the total cost of firm transport, less MDDQ costs, by transport volumes (Footnote 1, Exh. No. MCC - 12, J.D.-7, p. 4).

Although Mr. Feingold and Mr. Ball rebutted MCC's gas cost analysis, which involved MDU's inability to verify MCC's gas cost calculations (Exh. No. MDU-K, pp. 2-4), MCC appeared to later resolve MDU's concern (TR pp. 320-323 and Exh. No. MCC-14).

Unlike MDU, MCC included a cost for capacity in its purchased gas cost analysis. This cost reflects MDDQ capacity cost which MDU incurs for transported volumes over WBIP's system. Furthermore, although this cost is a "demand" or capacity cost on WBIP's tariff, MCC included it in its development of purchased gas energy costs.

Demand. In this section marginal demand cost, the second of MCC's two different production gas energy costs (FOF 168), is summarized. Although MCC noted a preference for forecast data, MCC used Mr. Feingold's historical distribution mains cost data to develop marginal demand costs. MCC revised MDU's data (Exh. No. MCC-12, p. 28) to remove replacement oriented ca-pacity projects, including one project which MCC claims is duplicative. As a result, each year's costs, 1984 through 1987, are less than MDU's estimates, as are additions to capacity (cf Exh. No. MDU-I, RAF-3 and Exh. No. MCC-12, JD-1, p. 3).

Later, MCC revised its initial marginal demand costs as follows. First, MCC removed service related investments which were labeled as customer-related (Exh. No. MCC-13, p. 7). Second, since MCC contends distribution mains serve both peak load and annual throughput purposes (Id., p. 8), MCC classified marginal demand costs 50/50 between capacity and energy.
MCC felt compelled to make this classification due to data limitations. To reconcile this problem, MCC suggests that the Commission require the Company to develop estimates of distribution capacity (demand) costs based on the cost of adding the least expensive increment to the system solely for capacity purposes (Id.).

Mr. Ball rebutted MCC's removal of five demand type projects MDU used for its marginal demand cost analysis (Exh. No. MDU-H, pp. 18-19). Mr. Ball concedes that Work Order No. 23581 is a replacement type project and should be removed from the analysis. However, Mr. Ball defended the remaining four projects.

MCC followed essentially the same methodology used by MDU in computing marginal demand cost adders. Differences exist, however, in the associated fixed O&M costs used by MCC.
MCC only added a fixed O&M charge and a revenue requirement for working capital based on materials and supplies and prepayments that were both less than those proposed by MDU. MCC initially applied the same nominal carrying charge used by MDU to annualize marginal distribution costs (Exh. No. MCC-7, JD-2), but later refined its analysis to reflect a real carrying charge based on the stipulated cost of capital in this Docket (see Order No. 5399a). MCC apparently made this change to be consistent with prior Commission LRMC decisions (Exh. No. MCC-13, p. 6).
MCC also justified the use of real carrying charges (MCC Response to DR PSC-310a). The result was a carrying charge of 12.29 percent, contrasted to the 17.59 percent computed by MDU and used by MCC in its initial testimony. The resulting marginal distribution cost, however, is

$13.21 per Mcf, because MCC revised its fixed O&M cost associated with capacity (Exh. No. MCC-13, JD-7, p. 2, and page A-1 of DR No. PSC-309-a). MCC's demand cost is summarized on Table C4.

MDU rebutted MCC's marginal distribution cost study on two counts. First, Mr. Ball rebutted MCC's revised marginal distribution costs. Specifically, although MDU agrees that investments in service lines are customer related, work orders used to develop distribution main costs do not include service lines. Further, MDU maintains that construction costs are limited to mains and service stubs (Exh. No. MDU-K, pp. 1-2 and DR PSC-262 a). Second, Mr. Feingold rebutted MCC's classification of distribution main costs. MDU contrasts MCC's direct and supplemental analysis noting that the energy classification is first introduced in MCC's supplemental testimony (Exh. No. MDU-L, pp. 4-6). MDU also maintains MCC's classification incorrectly assigns fixed costs to MDU's interruptible sales and transportation service customers.

Customer. MCC used an embedded cost analysis to calculate customer costs based on MDU's jurisdictional test-year total cost study (statement M), and Mr. Clark's proposed revenue requirement analysis (Exh. No. MCC-12, pp. 33-39). MCC cited three reasons for using an embedded COS method to compute customer costs. Those reasons are: 1) "the definition of the margin is conceptually more difficult for customer costs than it is for gas supply costs"; 2) marginal customer cost measurement is more difficult than for gas supply costs; and 3) there is less reason to be concerned with marginal customer costs then there is for marginal gas supply costs (Id., pp. 38-39).

MCC disagreed with MDU's method of developing customer costs. First, MCC maintains that due to changes in the natural gas market gas utilities, including MDU, have sought to protect themselves from such market risk by shifting greater portions of nongas costs to fixed charges borne by customers with fewer viable, short-run alternatives to natural gas (Id., pp. 33-34).

MCC described MDU's analysis to classify 40 percent of distribution main costs to customer, 30 percent to demand which is allocated to customers according to the proportion of peak demands. The remaining 30 percent is classified as commodity related and allocated to customers per their usage requirements. MCC states that MDU's treatment of distribution mains as regards customer costs reflects a minimum distribution approach (Id., p. 35).

MCC maintains MDU's 40 percent classification of distribution mains to customer costs is inappropriate since it makes an inaccurate measure of cost responsibility for the various rate classes and puts too much burden on the residential class. Further, MCC claims that distribution mains must be sized according to the loads they are to handle. Since distribution mains serve to deliver gas from the transmission facility to service lines, there must be sufficient capability to meet noncoincident peak demands. However, MCC holds that the same mains must serve average energy requirements (Id., pp. 36-37).

MCC proposed classifying customer costs as 50 percent demand related costs, in proportion to peak demands of distribution customers, and 50 percent be classified as energy related. MCC also notes that other costs such as land costs, structures and improvements, and metering and regulating equipment are affected by these changes in allocations (Id., pp. 37-38 and JD-3). It appears that only changes in revenue requirement, per Mr. Clark's supplemental testimony, resulted in a revised custom er cost study (Exh. No. MCC-13, p. 9 and JD-9).

Cost Allocation and Reconciliation

MCC departs from the allocation and reconciliation sequence in Table 1. MCC first reconciles functionalized total costs and then allocates costs (Exh. No. MCC-12, JD-1 and 3). MCC applied a non-equal percent method of reconciliation. MCC applied a 1.57361 reconciliation factor to just production and distribution costs (Id., JD-2). A summary of MCC's marginal cost class revenue requirements is provided in Table C5.

MCC allocates reconciled functionalized total costs to each customer class using factors that reflect the number of units each service cost category took during the year. (Id., p. 41). Table C6 contains the allocation factors MCC used, which include: 1) annual energy consumption at the distribution and transmission levels used to allocate purchased gas costs; 2) peak-day MCF (although not used as a direct allocation factor for reconciled total marginal costs, MCC used these volumes to compute total marginal demand costs prior to reconciliation andallocation); 3) 2-day peak MCF, used to allocate 50 percent of the distribution demand costs; and 4) annual energy consumption at the distribution level used to allocate 50 percent of the distribution demand costs. The 2-day peak MCF factor is based on peak volume related responsibility for each class during the year. The two inputs used to develope this factor were "class coincident peak demand during the peak season" (Id., p. 43) and "each class' total responsibility" based on its share of peak season demands.

The above includes several revisions MCC made to its COS analysis. First, peak day interruptible loads were removed from MCC's determination of peak day costs and his allocation of peak costs. The witness maintains that this adjustment was appropriate with regard to changes made in distribution main costs. MCC states that "it is only the commodity requirements, rather than peak demand requirements that should affect the allocation of costs to" interruptible customers (Exh. No. MCC-13, p. 9). Second, MCC allocated total distribution costs equally to demand and customer prior to reconciling revenues (Id.,JD-8). Specific allocations were provided in an MCC data response to the PSC (DR No. PSC-309a).

Rates 81, 82 and 90

In addition to including commercial interruptible, contract industrial, and transportation classes in its marginal cost studies, MCC suggests that the long-run marginal costs estimated for those interruptible and transportation customers receiving service through the distribution grid should include energy costs associated with investments in distribution mains (Exh. No. MCC-13, p. 16).

V. COMMISSION'S DECISIONS: COST OF SERVICE

The Commission's decision in this Docket is complex, and reflects the issues raised by the various parties. The decision on COS is organized as follows. The COS model in Table 1 serves to organize the Commission's decisions. Following a brief comment on the relevant cost perspective the decision will discuss in turn, cost functions, classification, allocation, reconciliation and moderation.

Cost Perspective

Traditionally, embedded cost of service studies determined each class' individual cost responsibility and prices. More recently, Commission policy has not applied embedded cost studies. The underlying reasoning is a concern for efficient resource allocation. The alternative costing approach embraced by this Commission involves marginal cost pricing.

From a policy standpoint, the Commission is in accord with MCC on the use of marginal cost studies to determine class revenue requirements and prices. MCC stated that because the use of marginal costs leads to a rate structure which meets the objectives of encouraging conservation, efficiency and equity, marginal costs should determine inter- and intraclass revenue requirements (Exh. No. MCC-12, pp. 11-13). The Commission is not inclined to embrace MDU's philosophy of mixing embedded and marginal costs to achieve the same results. The Commission would add that because regulation seeks to simulate the results of competition for an industry characterized by monopoly, margin al cost pricing recommends itself in the design of gas prices.

The Commission notes that this is the first time it has received comprehensive marginal cost analyses for MDU's gas system. It is also the first occasion that MDU's marginal gas cost have been debated with rigor before this Commission. The parties were not totally at odds on their marginal cost theories. As it has in other recent dockets, the Commission finds merit in combining the best elements of each party's cost studies. In certain instances the Commission chose to differ from both parties in the calculation of certain costs based upon its technical analysis of the data. Table C7 in the Technical Appendix summarizes these costs.

One other comment is necessary. In this docket issues arose that relate to issues in another ongoing MDU docket (No. 88.8.23). Because this other docket is ongoing and because MDU's testimony in the present Docket No. 88.11.53 used Interim results from Docket No. 88.8.23, certain decisions in this docket will be further addressed, and could be modified, when a final order in Docket No. 88.8.23 is issued. This is an unavoidable consequence of MDU's having made several rate design filings that were separately docketed.

Functionalization

Energy The Commission accepts but modifies both parties' estimates of marginal energy costs. Whereas MDU and MCC correctly used WBIP energy costs, the Commission finds that two changes are required.

First, the Commission finds merit in using the most current WBIP cost data available. From WBIP's 20th Revised Sheet No. 10, indicates that the WBIP commodity cost of gas is $2.76/dk, a value that exceeds either MDU's or MCC's, both of which are dated. Although not part of the record, the Commission takes notice of and will use the prices on WBIP's 20th Revised Sheet No. 10, which provides WBIP's current G-1 prices. The following compares costs from a data response to MCC (Exh. No. MCC-5-9), which the Commission could use, and WBIP's 20th revised Sheet No. 10:

	Commodity ($/dk)		Demand ($/Mcf/yr)	
	Gas	Non-Gas	AEQ	MDQ
1) Exh No. MCC 5-9:	1.78	1.071	.293	44.34
2) WBIP's 20th Revised Sheet No. 10	1.373	1.388	.335	42.46

Second, the Commission finds merit in adding to the $2.76/dk cost, WBIP's AEQ charge of $.335/Mcf. Similarly, itappears MCC included ADQ costs in its MC study (see MCC Exh. No. 14, JD-7, p. 4). The Commission finds merit in adding AEQ charges to energy costs to recognize the cost associated with obtaining annual throughput in WBIP's system. With line losses the resulting energy cost equals $3.13/dk. For interruptible sales, the AEQ cost is excluded with the result that the marginal energy cost equals $2.76/dk.

As a result of the above decisions, the energy cos portion of providing transportation service can be derived. This cost equals $.030/dk for firm and interruptible transportation. Clearly there should be a line loss cost difference, given firm loads may be taken on peak at any time during the winter season, while interruptible sales may not. However, no party analyzed incremental seasonal line loss costs. Until more accurate cost data is provided, the same energy cost will be used for firm and interruptible transportation.

Demand The Commission's marginal demand costs have two components, as does MCC's. First, the Commission accepts, in this docket, both party's recognition of distribution demand costs. The Commission finds more accurate and adopts MCC's distribution cost estimate of $13.21/Mcf. The Commission accepts MCC's results due to the use of a real carrying charge and the exclusion of all unneeded replacement cost investments.

The second demand cost component reflects WBIP's charge for peak use of its transmission system. MDU's marginal cost study excludes any such costs. MCC includes WBIP's MDDQ charge to MDU for firm transportation in its purchased gas cost estimate (Exh. No. MCC-14, JD-7, p. 4). This charge emerged when WBIP became an open access transporter and MDU could then convert certain firm purchases from WBIP to firm transport.

While the Commission finds MCC's recognition and use of the MDDQ in its marginal cost study laudable, the Commission finds that the MDDQ understates the marginal cost of peak demand to MDU. The absence of any peak demand charge in MDU's marginal cost study is in error. However, rather than using MCC's proposed MDDQ demand costs, the Commission finds that WBIP's MDQ charge is the relevant demand cost for WBIP transportation service. The reason for this finding includes the following. MDU admits the MDQ is relevant although not included in any MC analysis (see MDU Exh. I, p. 9, and MDU's proposed Standby Rate 83tariff). Another reason is that if MDU were to experience areduction in peak day demand, it is only logical to back off of the highest cost source first: the MDQ charge exceeds the MDDQ charge by about $11.28/Mcf per annum. Last, MDU itself admitted that the firm transport volumes for which it incurs MDDQ and ADQ charges is a "base volume" for which MDU would not reduce takes (MDU Exh. No. I, p. 8).

Customer. The last cost function to review involves customer costs. The Commission finds relatively more merit in MDU's customer cost analysis than MCC's. MCC used embedded costs and and as a result of pricing below embedded costs effectively placed the residual costs on energy and demand (MCC DR PSC-114-i). The Commission finds that MDU's marginal costs must of necessity be changed, however. First, consistent with the Commission's policy on excluding replacement costs in MC studies, MDU's costs are reduced by the amount of costs associated with "mains and service stubs." This leaves regulator and meter investment costs. The Commission's current policy is to include the meter and regulator investment costs in a MC study based on opportunity cost arguments. This was the Commission's policy in recent gas (e.g., MPC Docket No. 87.8.38) and electric dockets (e.g., MDU Docket No. 86.5.28). Second, the Commission finds a real carrying charge must be used to annualize customer costs.

Last, the Commission accepts, at this time, MDU's customer related O&M and A&G costs. Table

C7 summarizes the Commission's calculated customer costs.

While MDU developed customer costs by class for Rates 60 and 70, customer costs were developed for each of Rates 71,85, 81, and 82. The Commission finds that customer costs for these classes are most appropriately allocated to Rates 71 and 85 based on meter size. MDU argued that since the type of meter, positive displacement or orifice, was the primary factor driving customer costs for Rates 71, 85, 81 and 82, LRMC pricing for these customers should include a monthly revenue contribution based on the respective customers' meter type. While pricing issues for Rate 71, 85, 81 and 82 customer classes are discussed in the rate design portion of this order, customer costs for these classes were computed using the average costs for orifice and positive displacement meters for each of Rates 71, 85, 81 and 82 and allocated to Rates 71 and 85 since customers served on Rates 81 and 82 must acquire such service through Rates 71 and 85, respectively. These costs are listed on Table C7 under small (positive displacement) and large (orifice) meters.

Year's Dollars For Cost Development

Although the Commission finds merit in MCC's proposal to use mid-year 1990 dollar costs in lieu of MDU's mid-year 1988 dollar costs, a rigid application of this proposal would result in costs expressed in mixed-year dollar terms. Such would be the results from the Commission's adopted energy and WBIP demand costs which are in November, 1989 dollar terms (per WBIP's 20th Revised Sheet No. 10 G-1 Tariff) and all other costs expressed in mid-year 1990 terms. The Commission's objective is to compute costs in roughly the year's dollars during which the prices will be in effect: there is no efficiency in pricing gas sold in 1990 based on 1988 costs. Achievement of the Commission's objective is satisfied by expressing all non-WBIP based costs in March, 1990 terms. This decision is consistent with all recent Commission decisions on cost of service.

Classification

The above functionalized costs must be classified as energy, demand or customer related. To a large extent this was already accomplished due to the above costs being computed on a unit basis.

Energy. First, energy costs comprise those listed in Table C7. These costs are classified as energy for the following reasons. WBIP's gas and nongas commodity costs ($/dk) are simply energy related. The addition of WBIP AEQ costs on a per Mcf basis with the above gas costs on a per dk basis should not cause alarm. AEQ costs are an annual cost associated with annual throughput which the Commission finds should be classified as energy. The adding of $/dk and $/Mcf should also not because for alarm, as MDU and MCC likewise added the two types of costs together in their respective analyses (MDU Exh. No. I, RAF-10, and MCC Exh. No. 10, JD-7, p. 4).

Demand. Second, the two types of demand costs discussed above should be totally classified as demand. As regards distribution demand costs, this decision adopts MDU's proposal. MCC classified the same costs as 50 percent demand and 50 percent energy. The Commission finds no basis for accepting such a proposal without more concrete evidence that such costs are energy related. With regard to MDQ demand costs, the Commission once again finds appropriate classifying 100 percent of the same costs as demand related. How demand related costs are allocated to classes will be discussed later.

Customer. Customer costs by their very nature should be customer related, not energy or demand related. The Commission classifies these costs in this manner.

Allocation

A discussion of cost allocation requires a separation of classes into four groups, (see Table C7) and a discussion of billing determinants for cost allocation is required. The first group is Firm Sales and includes 60, 70 and 83. The second is interruptible sales and includes 71, 85 and 90. The third is firm transportation and includes Rate 84. The last is interruptible transportation and includes Rates 81 and 82. Next, how energy, demand and customer costs are allocated to these groups is discussed.

Energy. Energy costs are allocated to all groups. Energy costs vary, of course, and depend on the quality (firm or interruptible) and nature (sales or transport) of service. Once more, Table C7 summarizes how all marginal costs are allocated to classes.

Demand. There are two types of demand costs, distribution and MDQ. Both kinds are allocated to all firm Rate 60 and 70 peak day loads. This decision is consistent with MCC's testimony but not MDU's as MCC allocated certain demand costs to interruptible customers. In addition to allocating both types of demand charges to Rates 60 and 70 the Commission finds that due to MDU's proposed minimum firm volumes (100/dk for Rate 71, 900/dk for Rate 85), these classes should be allocated demand costs for that portion of their firm loads that could occur on peak days. As an initial conservative estimate the Commission has assumed the 100 and 900 dk minimum volumes are spread evenly throughout the month. Thus, for example, a Rate 71 customer is assumed to have 3.33 peak day Mcf volumes. Last, the merit of including WBIP demand charges in the cost of firm Rate 84 service raises issues that will be resolved in Docket No. 88.8.23.

The Commission finds allocating distribution demand cost to Rate84 appropriate when firm volumes arise.

Customer. In this docket the Commission finds necessary a separation of customer classes into two groups for purposes of cost allocation. One includes flexibly priced classes and the other group all other classes. First, consistent with the Commission's policy to exclude mains and service stub costs, the Commission finds merit in not allocating any such costs to flexibly priced customer classes. Customers served on flexibly priced tariffs will incur a meter and regulator charge as a result of the prerequisite that they take Rate 71 or 85 service.

Thus, no need exists to recover the same costs twice, unless of course service is taken through two or more meters.

The Commission finds that flexibly priced customers must pay the full cost of any added plant investments and/or transactions costs MDU might otherwise incur to provide service, excepting those meter costs recovered in customer charges. The alternative is to fully allocate all long-run marginal costs to these customers, much as MCC argued. However, the current estimate of these future costs is uncertain. This is one reason the Commission has made the present decision. For example, once a customer takes flexibly priced service, the replacement cost, should it ever arise, for any direct plant investments for mains, stubs or otherwise, shall never be allowed in cost of service but rather must be handled as customer contributed capital and totally recovered from the flexibly priced customer for which the cost was incurred. Other ratepayers will not be burdened with any future costs to replace plant to serve flexibly priced customer's loads. As MCC testified, should any transactions costs arise, the flexibly priced customers must again take total cost responsibility. A flexibly priced customer's load who later chooses a nonflexibly priced tariff shall not escape cost responsibility for all later direct plant investment costs.

For all other classes customer costs must be allocated as summarized in Table C7. The Commission would note that whereas MDU and MCC proposed Customer Charges that assumably vary by costs, the Commission was unable to discern any separable costs in this docket. Only for Rate 71 and 85 customers were there separate costs available for the two different meter types.

Where the Commission could discern customer cost variations the costs allocated to a class similarly varied.

Billing Determinants. The method by which unit costs are totalled and allocated to classes (uses billing determinants). The Commission's decisions on billing determinants are summarized in Table C8. The reasons for using this data are as follows:

Energy. First, for Rate 60 and 70 energy sales volumes there was no difference of opinion between MDU and MCC, and the Commission adopts their recommendations. The exception being that the Commission has imputed annual volumes associated with MDU's proposed 100 and 900 minimum firm volumes per month for interruptible customers into Rate 70 (Exh. No. MCC 2-1).

For cost allocation purposes the Commission also reflected 1,130 dk of Rate 93 volumes in Rate 70.

For Interruptible sales and Transportation Rates 71, 85, 81 and 82, the Commission adopted volumes proposed by MCC (Exh. No. MCC-11). For transportation related energy volumes the Commission also made certain adjustments. Rate 97 volumes were all put on Rate 82. Although a revenue requirement issue, the Commission will impute a conservative value for these shifted volumes of 861,117 based on the Rate 82 floor price MDU proposed.

Demand. Second, for demand related billing determinants, the Commission adopts those that MDU and MCC agreed on which total about 72,538 for firm Rates 60 and 70. Again, the Commission finds necessary an adjustment to reflect MDU's proposed minimum firm volumes of 100 and 900 per month respectively for Rates 71 and 85. However, since the volumes relating to MDU's proposed minimum firm volumes for Rates 71 and 85 have been added to the Rate 70 volumes, peak-day MCF for Rates 71 and 85 are added to Rate 70 peak-day MCF for allocation purposes.

Customer. For Rates 60 and 70 the Commission adopted the values MDU and MCC used, which were the same. The Commission used numbers for other classes as follows: The Commission used 23 Rate 71 and 7 Rate 85 customers (Exh. No. MCC 7-8). These customers were then divided into small and large meter groups based on the number of customers shown to be served by an orifice meter on MDU's Late Filed Exhibit No. 3, Att. A, pp. 1-3.

Table C9 summarizes the Commission's total classified marginal costs resulting from applying billing determinants shown on Table C8 to classified cost in Table C7.

Reconciliation and Moderation

The Commission finds that an equal percent reconciliation must be used to reconcile the allowed revenue requirement to the total marginal cost revenue requirement. Table C10 summarizes the Commission's reconciliation. This decision is also consistent with all recent Commission orders on cost of service. In this docket the total marginal cost of service falls below the Commission allowed revenue requirement. Consequently, if the Commission does not adjust upward one or all classes' marginal cost revenue levels, MDU would not have an opportunity to earn its allowed rate of return. However, the Commission will moderate, as it does in all dockets, a strict equal percent reconciliation to address this problem. Such moderation is discussed below.

The Commission finds necessary the moderation of revenue requirement impacts that arise from a strict equal percent reconciliation. This moderation discussion proceeds first with a review of recomputed pre-interim class revenues, labeled "Adjusted Pre-Final Revenues" on Table C11, followed by a discussion of the Residential and Commercial classes. The Commission found it necessary to recompute preinterim revenues for Rates 60, 70, 71, 85, 81 and 82 in order to establish a starting point for its interclass revenue moderation. Annual volumes and bills are based on those presented in Table C8, with the exception of 1,130 dk for Rate 93, which were removed from Rate 70. Tariffed Base Rates and Commodity Charges for Rates 60, 70, 71, and 85 prior to Order No. 5399 were used along with adjustment factors per MDU's interim workpapers, received February 13, 1989. Revenues for Rates 81 and 82 were based on ceiling prices effective prior to Order No. 5399. Rate 97 revenues imputed as Rate 82 were computed at 9c per dk.

For the Residential class the range in percent increases in revenue requirement equalled .89 percent per MCC up to 7.23 percent for MDU. Second, with regards to Rate 70 (commercial firm) the range in percent increases or decreases, as the case may be, varied from -2.18 percent by MDU to +2.9 percent by MCC. Table C12 summarizes the parties' proposals.

In its final deliberation over moderating interclass revenues, the Commission finds reasonable to hold fixed revenues for Rates 71 and 85 at the adjusted pre-final level. This decision is made due to the relatively elastic nature of service to these customers. Further, revenues for Rates 81 and 82 were set at the floor prices for each class plus minimum monthly customer charge related revenues and revenues generated from nomination fees. The remaining collectable revenues were added to the adjusted pre-final revenue requirements for Rates 60 and 70 using an equal percentage increase of about 1.13 percent. Rate 70 revenues were adjusted upward prior to applying the equal percent increase to account for 71,830 dk of firm sales volumes for Rates 71 and 85. These volumes were valued at pre-interim prices. The Commission's moderated class revenue requirements are summarized on Table C11.

This summarizes the Commission's cost of service decisions. The balance of this order discusses each party's Rate Design proposals and the Commission's decisions on Rate Design.

PART 5

RATE DESIGN

Introduction and Organization:

As with COS, both MDU and MCC filed rate design and pricing testimony. This part of the order will, in turn, review margin sharing and RD issues. First, MDU's and MCC's testimony on a margin sharing mechanism will be reviewed, followed by a Commission decision on margin sharing. Next, MDU's and MCC's RD and pricing testimony will be reviewed, followed by the Commission's decisions.

I. MARGIN SHARING MECHANISM

MDU. MDU proposed, for the first time, a MSM. The following provides MDU's reasoning for the MSM proposal and a description of how the MSM works.

MDU maintains that a MSM is needed for three general reasons. First, there is a high degree of uncertainty regarding the level of expected sales and transportation service for the near-term. Second, MDU expects volatility in revenues recovered from interruptible customers. Third, MDU experiences customer migration from sales to transportation. MDU holds the MSM will lead to an equitable balance of risks and benefits between itself and its firm customers. MDU states that the need for a MSM arose when WBIP became open-access, combined with MDU's being allowed flexible pricing.

MDU's MSM would appear to be implemented as follows: First, in this Docket all interruptible and firm transportation revenues and volumes would not be recognized. Thus, the Company's revenue requirement would be recovered from two customer classes: residential and commercial firm. Second, at a future time MDU would file with the Commission recognition of revenues and volumes for the MSM affected tariffs (i.e. Rates 71, 85, 81, 82, 83, 84, 90). At that time revenues identified with MSM affected tariffs, but recovered from the firm residential and commercial classes, would be shifted back to the MSM affected tariffs.

MCC. MCC conditionally opposed MDU's proposed MSM for the following reasons. First, since MDU and WBIP are affiliates MCC believes MDU Resources, Inc. can decide whether itsdistribution or transmission company absorbs price reductions to enhance sales. MCC suggests that the Commission move in a direction which motivates WBIP to bear the burden of such costs rather than passing them through to core customers. MCC also appears to suggest that WBIP will not be motivated to adjust its prices down to market levels so long as the Montana Commission indulges in the gerrymandering of costs to make this gas marketable. That is, MCC suggests MDU's MSM may be a ploy on MDU Resources' part to shift costs, that WBIP should otherwise absorb, to captive core customers.

Second, MCC holds that the Commission should adopt LRMC floor prices only if MDU's MSM is adopted. MCC states, that linking the two ideas will minimize the inappropriate and adverse impacts of MDU's MSM proposal. However, MCC holds that if the Commission adopts its proposal, price floors should be set equal to short-run marginal costs plus a contribution to fixed costs.

MCC stated it finds acceptable a 90/10 sharing of incremental revenues. MCC holds that if all appropriate test-year margins were allocated to the interruptible and transportation classes and if additional incremental sales (i.e., sales not included in test year demand and commodity cost allocators) are made at promotional rates, then a 90/10 sharing of revenues, may provide benefits to all system customers.

MDU rebutted MCC's argument that MDU's MSM should be tied to LRMC price floors. Mr. Feingold alleged an apparent inconsistency in MCC's position that, on one hand, floor prices should be short-run marginal cost based, while elsewhere floor prices should recover SRMC plus a contribution to fixed costs (Exh. No. MDU-L, p. 10). In this regard, MDU states that price floors are an intraclass price issue and the MSM is an interclass issue, and the two should not be confused. MDU holds the consequences of MCC's argument to set price-floors equal to LRMC is that there would be little or no opportunity for MDU to achieve interruptible sales or transportation margins, which could serve to reduce firm sales rates, and would hamper MDU's opportunity to earn its revenue requirement.

The Commission denies MDU's MSM and MCC's 90/10 sharing of incremental revenues proposal. Each is discussed in turn. The Commission denies MDU's MSM for a number of reasons.

First, it is not clear to the Commission that MDU's MSM would serve to enhance sales over and above the flexible pricing incentive. A number of points are relevant in this regard. MDU has experienced increased sales volumes and revenues since flexible pricing was implemented, relative to earlier experience. Also, flexible price floors would not vary in relation to whether there is or is not a MSM. Second, the Commission finds no need for a 90/10 sharing of incremental revenues between ratepayers and shareholders. MDU already has an opportunity to earn a reasonable rate of return. Therefore, MDU should not have to be enticed to use its distribution system efficiently.

II. MDU's RATE DESIGN TESTIMONY

MDU' RD witnesses included Mr. Ball, Ms. Aberle and Ms. Rick. MDU's RD considered such factors as customer impacts, understanding and acceptance, competitive pressures and the marginal and embedded cost study results. Some general changes MDU proposed include: 1) merging firm Residential and Commercial tariffs; 2) raising Base Rates; and, 3) a decliningblock rate structure.

Firm Sales: Residential Rate 60 and Commercial Rate 70

MDU proposed to merge firm residential Rate 60 and commercial firm Rate 70 into one tariff called Firm General Gas Service Rate 60. MDU cites the following three reasons for this consolidation: 1) marginal and embedded unit demand and commodity costs for residential and commercial firm customers are very similar, 2) service for both customer classes is firm and representative of MDU's core market for which firm gas supplies have been contracted, and 3) administrative efficiency as well as customer understanding can be enhanced.

MDU proposes increased Base Rates to recover customer costs. In so doing, MDU proposed Base Rates that vary by meter size using a 500 cubic foot per hour criteria. Under this proposal, small and large Residential customers Base Rates would equal $4.50 and $9.00/month respectively. For Commercial customers monthly Base Rates would equal $8 (small) and $16 (large).

MDU proposed a three-tier declining block rate structure for firm general service customers. The Company's reasoning is that all customer costs will not be recovered through Base Rates. Therefore, MDU needs to recover access costs "as soon as reasonably possible based on usage" (Exh. No. MDU-C, p. 27). MDU's proposed declining-block prices follow:

Usage Block	Non-Seasonal	Seasonal Winter	Seasonal Summer
First 5 dk per month	$4.662	$4.703	$4.289
Next 5 dk per month	$4.512	$4.553	$4.139
Over 10 dk per month	$4.362	$4.403	$3.989

Interruptible Sales:

Commercial Rate 71, Industrial Rate 85 and 90

Rate 71. MDU proposed a $35.00 Base Rate, a $3.388/dk Commodity charge and 3.3 dk/day of maximum daily firm requirements for this interruptible Commercial Sales tariff.

Rate 85. MDU proposed a $265.00 Base Rate, a $3.41/dk Commodity charge and a 30 dk/day maximum daily firm requirement for this interruptible Industrial Sales tariff.

Rate 90. MDU proposed a Base Rate equal to the customer's otherwise applicable Rate 71 or Rate 85 base rate (Application Appendix C). MDU further proposed that the Base Rate be differentiated by meter type (Exh. No. MDU-G). MDU proposed a commodity floor price which exceeds the weighted average commodity cost of gas from MDU's suppliers plus $.101 and any additional gas line loss costs.

Interruptible and Firm Transportation Rates 81, 82 and 84

Rate 81 To take Rate 81 Service MDU proposed that the Rate 81 customer must otherwise be eligible for Rate 71 service. The minimum firm load requirements (See FOF 243) would be billed at proposed Rate 60 or Rate 84, whichever is applicable. A $35 Base Rate was also proposed. MDU proposed floor and ceiling prices of $.101 plus applicable gas losses and $.518 respectively. MDU calculated a $.041/dk gas loss cost.

Rate 82. To take Rate 82 service MDU proposed that the Rate 82 customer must otherwise be eligible for Rate 85 service. The minimum firm load requirements would be billed at Rate 60 (70) or Rate 84, whichever is applicable. A $265 Base Rate was proposed, combined with floor and ceiling prices the same as those on Rate 81.

In addition to the above, MDU proposed the following:

Based on its LRMC study for interruptible sales and transportation customers, interruptible transportation prices should include a minimum monthly revenue contribution based on the type of meter served by each customer (Exh. No. MDU-J). Specifical ly, MDU used the average marginal customer cost for customers served by positive displacement and orifice meters as a basis for a minimum monthly contribution. MDU proposed that customers served by positive displacement and orifice meters contribute a minimum of $210 and $1,325 per month, respectively. Additionally, MDU proposed a floor price of $.101 per dk plus any gas line loss costs based on the weighted average cost of gas per MDU Docket No. 88.11.48 calculated at $.041 per dk (Exh. Nos. MDU-C, MDU-G, and TR pp. 178-180).

Rate 84. The Rate 84 customer must otherwise qualify for Rate 71 or 85 service. A flat non-flexible transportation price of $1.19/dk was proposed. One of two different Base Rates $35 (Rate 71) $265 (Rate 85) would be charged. In addition to the above specific tariff changes, MDU proposed to change certain of the General Terms and Conditions (GT&C) generic to all three transportation tariffs. These changes include, 1) additional language to MDU's specification on multiple service provisions including minimum firm billing, 2) removal of a required transportation agreement to receive service, and 3) a section describing the method customers are to use to make daily gas nominations.

Additional Rate 71, 85, 81 and 82 Proposals

Minimum Firm Volumes: Rates 71, 85, 81 and 82. Due to the firm requirements of its interruptible sales and transportation customers, MDU proposes a 100 dk for Rate 71 and a 900 dk for Rate 85 per month minimum firm volumes as representative of the average firm use for these customers. In the past, firm volumes were billed under MDU's firm service rate. Customers without separate metering capabilities will be billed for the above stated minimum monthly volumes under Rates 70. (Exh. No. MDU-C and Appendix C of Application). MDU proposed billing Rate 81 and 82 firm volumes should the need arise, under Rates 70 or 84 as applicable (Application Appendix C).

Availability Section of Rates 71, 81, 82 and 85.

MDU proposed to retitle Rate 85 as, "Large Industrial General Gas Service Rate 85." MDU's proposal maintains that a qualifying Rate 85 customer must maintain a 100,000 dk annual minimum load requirement. MDU supports this change by maintaining that the only distinction justifying a separate industrial rate is based on load size cost causation. A similar change is proposed for proposed Rate 71, Interruptible General Gas Service. Rate 71, will be required to maintain gas loads between 6,000 and 100,000 dk. MDU contends that the 100,000 dk break point reflects higher metering cost related to serving larger loads.

Corresponding load requirement changes are also proposed for transportation Rates 81 and 82 (Exh. No. MDU-C).

Standby Rate 83

MDU proposed a standby service for those interrptible customers wishing to reserve capacity in the event that their alternate fuel sources are interrupted. MDU's proposed rates include four elements. First, the Base Rate would equal the customer's otherwise applicable sales or transportation tariff. Second, MDU proposes to assess pipeline demand charges equal to the amount MDU pays for pipeline demand reservations, i.e., AEQ and MDQ charges (TR pp. 283-285). Third, MDU proposes a $.163 per dk per month distribution demand charge. Fourth, MDU proposes a commodity charge equal to the retail sales tariff commodity charge less any pipeline or distribution demand charges paid for separately under this Rate (Exh. No. MDU-C and Application Appendix C).

Optional Seasonal: Residential and Commercial Service Rates

MDU proposes to consolidate its Optional Seasonal Residential and Commercial Service Rates 62 and 72, respectively, into a single optional rate, entitled Optional Seasonal Firm Gas Service Rate 62. MDU proposed Base Rates the same as those proposed for Rate 60, outlined above. However, MDU proposes a winter/summer seasonal differential based on the annual weighted average demand costs MDU pays WBIP for its gas and transportation purchases from WBIP (Exh. Nos. MDU-C and MDU-G). This differential equals $.414. MDU also proposed that future differentials reflect currently effective gas trackers.

MDU's seasonal prices recognize purchased gas demand costs incurred by MDU while not setting the winter price too far above the flat annual price. Hence, MDU assigned only part of the MDQ and MDDQ costs to the winter period by levelizing these costs over the full year. MDU defined the winter season as September 16 through May 14, leaving the summer period as a step toward minimizing the impact on winter price levels (Exh. No. MDU-G and Application Appendix C).

Other Tariff Changes

Tariff Volume No. 4. MDU proposes to cancel its second tariff volume and replace it with Volume No. 4. MDU's intent is to provide a more clear and concise explanation of the application of rates, to move several rules to a new general provisions tariff (Rate 100) and to put the Company's rates, rules and regulations on a uniform numbering system.

Rates 100, 101, 102, 114, 121 and 122. MDU proposed a new Rate 100 which consolidates several currently separate tariffs, including Rates 101, 102, 114, and 122, with minor terminology changes made to these tariffs. Additionally, Rate 100 addresses the Company's common business practices.

Rate 89. MDU proposes to remove Rate 89, Incremental Natural Gas Pricing Provision, from its tariff, since the FERC terminated its incremental pricing program as of July 30, 1987, and revoked its regulations under Title II of the NGPA as of January 1, 1988. MDU contends that Rate 89 is therefore no longer needed.

Rate 117 Returned Check Charge. MDU made two proposals regarding Rate 117. First, MDU proposes a $10 charge for each check returned to MDU due to nonsufficient funds. MDU claims that it incurs an $11 cost for handling returned checks.
Second, MDU proposes some cost related language changes to the unauthorized use of service section regarding Company owned property and MDU's description of utility services.

Rate 135 Late Payment Charges. In addition to relocating Rate 135 under proposed

Rate 100, MDU proposed to change its late payment charge (LPC) rules for nonresidential customers
in order to apply a LPC to unpaid balances at the "immediate subsequent billing date" (Exh. No. MDU-E, p. 4). The LPC is currently applied to unpaid balances outstanding at the second subsequent billing date.

Gas Extension Policy Rate 120. Other than clarifying language changes in Rate 120, MDU proposes this Rate be changed to reflect income taxes born by MDU in providing gas main extensions, pursuant to the Tax Reform Act of 1986 and PSC Order No. 5236f.

III. MCC'S RATE DESIGN TESTIMONY

The following summarizes MCC's direct and supplemental RD testimony with MDU's rebuttal testimony interwoven as appropriate. It appears MCC limited its quantitative RD testimony to Rates 60, 70, 71 and 85. MCC provided qualitative testimony limited to flexibly priced transportation Rates 81 and 82. A summary of Residential and Commercial Firm Rates 60 and 70 will be followed by Interruptible Sales and Transportation Rates 71 and 85. Additionally, MCC's position on transactions costs for flexibly priced transportation customers are reviewed. MCC did not appear to provide analysis for Rate 84. MCC's quantified proposed rate design is summarized in Table 2.

Firm Sales: Residential Rate 60 & Commercial Rate 70

MCC proposed separate tariffs and Base Rates for Residential and Commercial Firm tariffs equal to those proposed by MDU. MCC designed a non-seasonally differentiated commodity charge for both the Residential and Commercial Firm Classes.
MCC maintains its Commodity charges reflect MCC's marginal costs. MCC contends that block rates are not needed since MCC's proposed revenue increases justify neither an increase in Base Rates or block prices as signals to customers of cost differences to serve large and small metered customers (Exh. Nos. MCC-12,
13, and 14).

Interruptible Sales: Commercial Rate 71 and Industrial Rate 85

MCC proposed Base Rates and Commodity charges for Rates 71 and 85. Those prices are summarized on Table 2.

Rates 81 and 82

MCC proposed Rate 81 and 82 transportation ceiling prices be set equal to the non-gas margin established for Rates 71 and 85, respectively (Exh. No. MCC-13, p. 15).

Table 2

MCC Proposed Rate Design

RATE CLASS	Customer Charge (per month) Small Meter	Customer Charge (per month) Large Meter	Commodity Charge (per dk)
Rate 60	$ 4.50	$ 9.00	$ 4.237
Rate 70	8.00	16.00	4.543
Rate 71	$ 6.00		4.270
Rate 85	265.00		3.655

Source: Exh. No. MCC-13, JD-10 and JD-11

MDU Rebuttal. MDU rebutted MCC's adoption of its proposed Base Rates noting that MCC's Base Rate differs from MDU's. That is, MCC's Base Rates for Rates 60, 70 and 85 equal those of MDU's. However, MCC proposed a Base Rate of $6 for Rate 71 which differs from MDU's proposed $35 Base Rate (Exh. Nos. MDU-H and K). Additionally, MDU rebuts MCC's rate design contending that it will perpetuate and aggravate interclass subsidies. MDU also notes that MCC's Commercial Interruptible Commodity charge is greater than its proposed Residential price.

Transportation

MCC argued that floor prices for transportation rates should be set at short-run marginal cost plus a fixed cost contribution, "directly allocable customer costs" (Exh. No. MCC13, pp. 16-19). MCC states that while transportation floor prices set at LRMC are laudable, such a rigid requirement is not needed due to regulatory policy goals. MCC argues that transportation prices set at LRMC could result in lost earnings. MCC supports that either a Base Rate, or MDU's proposed minimum revenue contribution based on meter size for transportation customers be used.

MCC contends that MDU should not be required to include transactions costs to the extent that none exist. However, MCC maintains that if such costs should arise in the future they should become the customer's responsibility. At hearing, Mr Drzemiecki clarified that transactions costs are those in which the buyer and seller can easily be identified and that the costs relate to a specific type of energy usage (TR pp. 327-331).

MDU Rebuttal. MDU rebuts MCC's position regarding transportation rate floor prices by noting that MCC has not quantified the floor prices MCC proposed. MDU further alleges an apparent inconsistency in MCC's definition of SRMC and its application of SRMCs to pricing transportation services (Exh. No. MDU-L, p. 10). Further elaboration is made in FOF 229, above.

IV. COMMISSION DECISION: RATE DESIGN AND PRICING

This section addresses the Commission's decisions regarding the various rate design issues in this docket. This section is organized as follows: Rate design decisions for MDU's Residential and Commercial Firm Rates 60 and 70 will be ddressed including MDU's proposed merger of these tariffs.

Next, pricing and availability decisions for MDU's interruptible sales Rates 71, 85 and 90 will be discussed followed by a similar discussion for MDU's interruptible and firm transportation Rates 81, 82 and 84. Third, Pricing and availability decisions for MDU's proposed Standby Rate 83 is discussed followed by a discussion on Optional Seasonal Rates 62 and 72 and Rate 93. Finally, the Commission's decisions on MDU's remaining tariff proposals are addressed.

Tables 3, 4 and 5 summarize the Commission's pricing decisions in this docket. Table 3 summarizes prices for Rates 60, 70, 71 and 85. Table 4 summarizes prices for Rates 81 and 82. Table 5 summarizes the Commission's pricing for Rates 62 and 72.

Residential and Commercial Firm Rates 60 and 70

The Following addresses the Commission's decisions regarding MDU's proposed merger of Rates 60 and 70, block pricing, Base Rates and Commodity Charge proposals. Each will be addressed in turn.

Table 3
Commission's Adopted Pricing:
Rates 60, 70, 71 and 85 1/

Class	Base Rate ($/Mo.) Small Meter	Base Rate ($/Mo.) Large Meter	Commodity Charge ($/dk)
Rate 60	$ 4.50	$ 9.00	$4.230

Rate 70	8.00	16.00	4.555
Rate 71	$ 35.00		4.197
Rate 85	265.00		3.622

1/ Prices are estimated and subject to final approval in MDU's
Rate Design Compliance filing.

The Commission denies MDU's proposal to merge Rates 60 and 70 into one tariff for two reasons. First, the Commission finds that even though Rates 60 and 70 may have similar characteristics such as associated elasticities, the Commission finds that for administrative and understandability purposes the two classes should be tariffed separately. Secondly, the Commission finds that since MDU has not presented sufficient marginal cost analysis for the provision of firm seasonal service to Rates 60 and 70 customers, the provision of firm gas service for these customers under a common Commodity Charge may result in forfeiting desired economic goals. For instance, since the Commission finds the per dk winter/summer cost differential, based on demand costs adopted by the Commission in this docket, differs for Rates 60 and 70 (see FOF 294), a common Commodity Charge would fail to signal the true cost of service for each of these customer classes at the peak. In the event that the seasonal cost differentials for Rates 60 and 70 diverges further, improper cost signaling could be aggravated. Such divergence may be caused by redefining the on and off-peak seasons or by escalated marginal demand costs. Therefore, without a thorough cost analysis for the provision of firm seasonal gas sales and an empirically supported definition of seasons, the Commission is reluctant to allow MDU to merge Rates 60 and 70 with a common Commodity Charge. Until MDU can explicitly show that the cost to provide on and off-peak service to these classes is not significantly different, MDU must tariff separately Rates 60 and 70. Further discussion regarding the Commission's findings on seasonal pricing for Rates 60 and 70 is contained in the section on Optional Seasonal Rates below.

The Commission finds unacceptable, at this time, MDU's proposed block prices for Rates 60 and 70. Although declining block prices for the firm gas customer classes may have economic merit with respect to recovering customer costs, provided the tail block price is set at marginal cost, the Commission bases its decision on MDU's insufficient cost analysis for providing seasonal service. Synonymous with the above stated reason to deny MDU's proposed Rate 60 and 70 merger, the Commission finds that by establishing block prices without thoroughly analyzing the marginal costs associated with the provision of seasonal service, block prices may aggravate further uneconomic prices that are not reflective of the true cost MDU incurs to provide service to Rates 60 and 70. Thus, until 1) a thorough cost analysis for the provision of firm seasonal gas sales consistent with the Commission's COS findings in this docket, and 2) an empirically supported definition of seasons, is filed by MDU, the Commission will not consider further declining block pricing for Rates 60 and 70.

Further, given the increased revenue requirement in this docket is minimal and the Commission is approving higher base rate charges to collect more customer costs from a fixed customer charge rather than in the commodity charge, further movement to collect customer charges through higher commodity charges is unnecessary at this time. Higher base rates tend to assure greater utility revenue stability and a more favorable commodity price for increased sales, but the Commission must balance that with the fact that in the absence of a need for a much higher revenue requirement, a declining block pricing structure at this time would place too great a burden on the inelastic monopoly served residential and commercial customers who have reacted to price signals and adopted conservation measures or lifestyle changes to minimize natural gas bills. Most small users have few economic alternatives due to the costs of heating system conversions and increased fixed charges without compelling revenue requirements. For economic reasons, it would be unfair at this time to transfer more customer costs to levels of consumption which are largely unavoidable by the customer.

Additionally, the Commission finds merit in MCC's argument opposing MDU's proposed declining block prices. As noted below, MDU presented no explicit cost justification for different meter sizes in its marginal customer cost study, hence, it is not known whether MDU's proposed base rates will sufficiently signal the correct cost differences for service with small and large meters. Further, it seems more likely that high-use customers will be signaled more accurately by the general cost differentials associated with their usage through higher Base Rates, rather than through declining block prices.

Although MDU's marginal customer cost analysis fails to explicitly express costs for different meter sizes for Rates 60 and 70, the Commission grants MDU's proposed Base Rates for small and large metered customers based on MDU's proposed 500 cubic foot per hour criteria. This decision is consistent with both MDU's and MCC's proposed rate designs. This decision results in Commodity Charges for Rates 60 and 70 of roughly $4.230 and $4.555 per dk, respectively. The Commission finds these prices sufficient to recover these classes' modified revenue requirements.

Although the Commission's estimated prices for Rates 60 and 70 included class revenue adjustment factors of .995655 and .999646 for Rates 60 and 70, respectively, the Commission questions why these factors are used (see MDU's interim work papers received February 13, 1989). Therefore, MDU will be required to justify the use of such factors in its next general rate case. Similar adjustment factors were used to compute commodity prices for Rates 71, 85, 62 and 72.

Interruptible Commercial and Industrial Rates 71, 85 and 90

The following discussion presents the Commission's decision regarding Rates 71, 85 and 90. Base Rates, Commodity Charges, maximum daily firm volumes, minimum firm volumes and availability constraints will be discussed, in turn.

At the outset, the Commission finds reasonable, and grants, MDU's proposal to tariff separately Rate 71.

Rates 71 and 85. The Commission grants MDU's proposed Base Rates for Rates 71 and 85 equalling $35 and $265, respectively. The balance of the Commission's modified revenue requirements are found to be recovered through Commodity Charges of roughly $4.197 per dk and $3.622 per dk for Rates 71 and 85, respectively.

The Commission grants MDU's proposed method of billing minimum firm volumes for Rates 71 (100 dk per month) and 85 (900 dk per month), using the Rate 70 Commodity Charge, in the event that a Rate 71 or 85 customer does not have facilities capable of metering firm volumes separately. However, the Commission finds that even though the monthly firm volumes MDU proposed are estimates, the the variation around these averages appears wide (Exh. No. MCC 2-1). Hence, there may be cases in which custom ers with no firm volumes will be subsidizing those with firm volumes exceeding 100 or 900 dk per month, as the case may be.

Exceptions may occur in cases where customers have installed the necessary equipment to separately meter firm volumes.

The Commission finds uncontested and grants MDU's proposed availability constraints for Rates 71 and 85 Additionally, the Commission grants maximum daily firm requirements of 3.3 dk and 30 dk per day for each of Rates 71 and 85 respectively.

Rate 90. The Commission finds the Base Rate applicable to Rate 90 customers proposed by MDU (Application Appendix C) acceptable in accordance with the Commission's decisions regarding Base Rates for Rates 71, 85, 81 and 82.

Commensurate with the Commission's adopted marginal
costs, the Commission finds MDU's application of the weighted average cost of gas purchased by the Company as part of the price floor for Rate 90 inconsistent with the Commission's adopted marginal energy costs. In order to achieve consistency with the Commission's adopted costs in this Docket, the Commission finds the Commodity Charge for Rate 90 shall not fall below the Commission's adopted marginal energy cost of roughly $2.791 per dk (see Table C7).

With regard to the remaining Rate 90 price elements, the Commission finds the $.101 and applicable gas loss cost price floor adequate until MDU can provide an acceptable marginal cost for the "other energy" costs it proposes as part of the price floor for Rate 90 (see Exh. No. MDU-C, DRB-4 and Application Appendix C). The Commission finds that gas losses shall be priced according to a 1.09 percent gas loss factor applied to the Commission's adopted marginal cost of gas per Table C7. The gas loss cost is embedded in the minimum Commodity Charge stated above.

Interruptible and Firm Transportation Rates 81, 82 and 84

The following discusses the Commission's decision re-garding Rates 81, 82 and 84. Base Rates, price floors and ceilings and transactions costs will be discussed for each of Rates 81 and 82 following a brief discussion of generic uncontested proposals for these classes. This will be followed with the Commission's decision on Rate 84 proposals.

Table 4
Commission's Adopted Pricing:
Rates 81 and 82 1/

	Min. Monthly Revenue		Transportation	
	Positive		Charge ($/dk)	
Class	Displacement	Orifice	Floor	Ceiling
Rate 81	$151.00	$1,192.00	$.131	$.560
Rate 82	190.00	1,161.00	.131	.560

1/ Prices listed are estimates and subject to final approval in MDU's Rate Design Compliance filing.

Rates 81 and 82. The Commission finds uncontested the availability constraints for gaining Rate 81 or 82 transportation service. Additionally, the Commission finds reasonable MDU's proposal to require that Rate 81 and 82 customers be eligible for service on Rates 71 and 85, respectively. Further, the Commission finds reasonable MDU's proposal to bill customers' minimum firm load requirements at Rate 70 for sales and Rate 84 for transported gas. However, the Commission does not know how MDU intends to bill for separately metered Rate 81 firm sales or transportation volumes (Application Appendix C, Vol. 4, Sheet No. 32). Therefore, the Commission seeks clarification of this language by MDU in its compliance filing, or removal of the language as appropriate. The Commission maintains the same comments provided above (FOF 274), regarding MDU's estimated firm loads for interruptible sales customers.

The Commission finds MDU's proposed minimum monthly revenue contribution to recover customers costs for Rates 81 and 82 based on meter type appropriate and grants this proposal with the following adjustments. Using the Commission's adopted marginal customer costs (Table C7), the Commission finds a minimum monthly revenue contribution of $151 and $1,192 for positive displacement and orifice metered Rate 81 customers, respectively, reasonable. For Rate 82 customers, a minimum monthly revenue contribution of $190 and $1,161 for positive displacement and orifice metered customers, respectively should be used. The Commission interprets these minimum monthly revenue contributions as contributions made in the absence of any transported volumes. As such, revenue generated as a result of MDU transporting gas to these customers will exceed the minimum revenue contribution according to the volumetric price MDU is able to negotiate with its customers. As stated in the COS part of this order, any costs relating to any direct plant investment for mains, stubs or otherwise due, to replacement of such plant or addition of such plant to gain a new customer, will be the sole responsibility of the flexibly priced customer.

Regarding Rate 81 and 82 floor and ceiling prices, the Commission adopts MDU's proposal with the following adjustments. First, the Commission finds the method MDU used to compute gas loss costs inconsistent with the Commission's adopted marginal costs (Table C7). Therefore, the Commission orders MDU to value gas losses for these customers according to the marginal energy cost of gas on Table C7. The Commission finds this cost to be about $.03 per dk. Secondly, the Commission finds reasonable MDU's use of "other energy" costs equalling $.101 per dk for the remaining floor price element adequate until MDU can provide an acceptable marginal cost for these "other energy" costs that it proposes as part of the price floor. Thus, the Commission finds a price floor of $.131 per dk for Rates 81 and 82 reasonable. Finally, the Commission finds it necessary to adjust MDU's proposed ceiling price according to the marginal distribution demand cost adopted in this order (Table C7). The resulting ceiling price is roughly $.560 per dk.

Although transactions costs were noted briefly in the COS part of this order (FOF 210), the Commission finds it necessary to discuss this issue further in the context of providing Rate 81 and 82 service. First, MDU's discussion regarding transactions costs appears limited to measuring these cost in increments, which MDU appears to define as additional personnel rather than additional man-hours (Exh. No. MDU-G). That is, MDU contends that since it has not hired any additional personnel to implement transportation services and flexible pricing, it has not incurred any transactions costs to provide such service.

The Commission finds that transactions costs need not necessarily be measured in increments as defined by MDU; rather such costs may be measured in man-hours devoted to, but not limited to administrative and general activities such as negotiating and maintaining contracts and handling daily load nominations. Using this definition, MDU may be incurring some transactions costs by shifting its staff's work load toward providing additional Rate 81 and/or 82 service. Second, the Commission finds merit in Mr. Drzemiecki's definition of transactions costs (TR pp. 327-331) in which both the buyer and seller must be identifiable.

To the extent that MDU is incurring transactions costs, as defined above, for providing Rate 81 or 82 service, the Commission finds each identifiable customer causing MDU to incur such costs must be responsible for paying those costs. In terms of measuring these costs the Commission finds that the use of time studies is one possible means. However, no determination will be made at this time on whether and how these studies should be conducted. Hence, transactions costs for providing flexibly priced services will remain an issue in MDU's next rate case.

Rate 84. The Commission finds MDU's proposed Rate 84 eligibility criteria reasonable. Furthermore, the Commission finds reasonable the $35 and $265 proposed base rates for Rate 84 customers taking service through Rates 71 or 85, respectively. The Commission adopts MDU's proposed flat, nontaxable transportation price for Rate 84, adjusted for the Commission's adopted marginal demand cost in this docket (Table C7). The resulting transportation price is approximately $1.325 per dk. The Commission approves this price to the extent that it does not conflict with issues in Docket No. 88.8.23.

General Terms and Conditions. The Commission finds the general terms and conditions proposed by MDU in this Docket for Rate 81, 82 and 84 uncontested and hereby grants MDU's proposals to the extent such grant does not conflict with issues in Docket No. 88.8.23.

Standby Service Rate 83

The Commission finds reasonable and approves MDU's proposed Standby Rate 83 with the following adjustments. First, the Commission finds MDU's proposed monthly base rate, as specified in the customers otherwise applicable interruptible sales tariff (Rate 71 or 85), reasonable. Second, the Commission also finds reasonable MDU's proposed Pipeline Demand Charge, but orders MDU to utilize demand charges per WBIP's G-1 tariff, consistent with the Commission's adopted marginal costs. Third, the Commission finds it necessary to adjust MDU's distribution demand charge to maintain consistency with its distribution demand costs (see Table C7), the result of which is roughly $.100 per dk. Although the Commission finds this charge reasonable in the instant docket, MDU should address refinements in conjunction with a redefinition of on-peak consumption and costs in its next Rate Case, as the calculation used herein is not limited to peak volumes for the firm classes.

Finally, the Commission finds merit in MDU's proposed Commodity Charge but limits MDU to netting out only the distribution charge adopted above, and pipeline demand charges per WBIP's G-1 tariff converted to flow variable terms using Rate 70 volumes.

As a means of verifying the Commission's findings for Rate 83, MDU should provide the Commission with the applicable prices that potential Rate 83 customers will face as a result of this order. MDU should provide such information with its rate design compliance filing.

Optional Seasonal Rates 62 and 72

The Following addresses the Commission's decision regarding MDU's proposed merging Rates 62 and 72, base rates and MDU's method used to calculate its seasonal price differential. MDU's definition of the winter and summer seasons is also addressed.

Table 5

Commission's Adopted Pricing:

Rates 62 and 72 1/

	Base Rate ($/Mo.)		Commodity 2/ Charge ($/dk)	
Class	Small Meter	Large Meter	Summer	Winter
Rate 62	$4.50	$ 9.00	$3.872	$4.292
Rate 72	8.00	16.00	4.161	4.597

1/ Prices are estimated and subject to final approval in MDU's Rate Design Compliance filing.

2/ Assumes seasonal differentials of $.468 and $.482 for Rates 62 and 72 respectively.

Dispensing first with MDU's proposed tariff merger and base rates, the Commission finds unacceptable MDU's proposed merger of Rates 62 and 72 for the same reasons it denied MDU's proposed merger Rates 60 and 70. Second, the Commission finds reasonable MDU's proposed base rates for small and large metered customers based on MDU's proposed 500 cubic foot per hour criteria for both Rates 62 and 72.

Third, the Commission makes the following comments regarding MDU's methodology used to compute its seasonal differential for Rates 62 and 72. In Order No. 5379 (FOF 73) the Commission found merit in and granted MDU's proposed optional seasonal prices, Rates 62 and

72. However, the Commission found that MDU's method of determining the seasonal differential was possibly in error. Upon review of MDU's method to compute the seasonal differential in the instant docket, the Commission maintains that MDU's approach remains in error for the following reasons.

First, the use of both MDQ and MDDQ costs to compute the seasonal differential appears inconsistent with MDU's intended use of non-WBIP gas purchases as base loads (Exh. No. MDU-I and FOF 142). Second, levelizing peak-division costs over the entire year seems to defeat the economic reasoning underlying seasonal pricing. This reasoning holds that prices signaling to customers the differences in costs associated with providing service during the peak verses the off-peak period are efficient. Prices failing to accurately signal such cost differences would not be efficient.

If MDU's seasonal price differentials were based on distribution and WBIP demand costs adopted by the Commission in this docket (see Tables A7-A9) and levelized over the annual Volumes of Rate 60 and Rate 70, the resulting differentials would be $.420 and $.436 per dk for Rates 62 and 72, respectively. However, if these same costs are levelized over winter volumes for each of Rates 62 and 72 (MDU's response to DR No. PSC-61a), the differentials are roughly 11 percent greater for eacclass.

Based on the above analysis and the Commission's findings in Order No. 5379, the Commission finds merit in computing the winter/summer differential MDU uses to design its seasonal Commodity Charges for Rates 62 and 72 using the distribution and WBIP demand cost adopted by the Commission in this docket. Further, since the Commission finds levelizing these cost over the entire year a move in the wrong direction, optional achievement of the economic goal for seasonal pricing dictates computing seasonal differentials using winter volumes.   The Commission notes, however, that according to its calculations using data provided by MDU (DR No. PSC-61a), the foregoing method would result in summer and winter Commodity Charges exceeding the annual flat Commodity Charges for the non-seasonal counterparts of Rates 62 and 72. To alleviate this problem, the Commission finds that either the modified revenue requirement for these classes must fall to at least the classes' total marginal cost, or Base Rates must rise. Since neither option is appropriate in this Docket, the Commission finds it acceptable to levelize summer/winter cost differentials for each of Rates 62 and 72 over annual volumes. MDU will be required to address the appropriate methods connected with levelizing seasonal cost differentials over these classes' peak season consumption in its next Rate Case.

Finally, the Commission notes that although MCC supported October through May as a winter season in this docket (Exh. No. MCC-12, p. 28), which appeared a stand-alone issue for MCC, no empirical analysis was filed by MDU to support its winter and summer seasons for firm sales. Therefore, the Commission finds adequate MDU's current seasonal definitions. However, the Commission directs MDU to provide thorough empirical analysis supporting on and off-peak gas consumption for Rates 62 and 72 in its next general rate case. MDU must show distinct seasons for firm gas service to its Residential and Commercial firm classes which are significantly different from each other.

Furthermore, such analysis must include a thorough cost analysis of providing firm gas sales service during on and off-peak seasons.

Rate 93

Though not at issue in this docket, the Commission finds that MDU's Rate 93, an apparent lease agreement priced at roughly $.043 per dk, is a non-tariffed service in Montana. As the Commission is unaware of the history behind this Rate, MDU should provide a brief history of Rate 93 and include this Rate in its cost of service analysis in its next Rate Case. The Commission directs MDU to file tariff sheets containing all terms and conditions under which MDU currently provides Rate 93 service.

Other Proposed Tariff Changes

The following addresses the Commission's decisions regarding all other tariff changes proposed by MDU.

The Commission finds MDU's proposal to retire Tariff Volume No. 2 and replace it with Volume No. 4 uncontested and grants MDU's proposal to the extent that Volume No. 4 reflects all of the Rate Design and pricing decisions in this Order. For instance, references to rates not approved in this Order will need changing.

With regard to Rates 101, 102, 114, 122 and 130, the Commission finds consolidation of these Rates under Rate 100, and the minor terminology changes, uncontested and acceptable to the extent that such consolidation and implementation does not conflict with other parts of this Order. A separate section of this part of the order has been devoted to portions of MDU's proposed Rate 100.

The Commission also finds acceptable and grants MDU's proposed removal of Rate 89 and the proposed changes to Rates 120 and 121. Regarding Rate 117, the Commission finds MDU's proposed Returned Check Charge of $10 per returned check reasonable and grants MDU's proposal.

While the Commission finds MDU's proposed changes to its LPC for nonresidential customers (Rate 135) acceptable, it is concerned that approval of MDU's proposed LPC in this docket may cause such customers unduly burdensome costs to convert their fixed billing systems to avoid late payment charges.

Therefore, the Commission directs MDU to include language in its LPC tariff providing allowances for customers with prearranged payment plans to adjust to MDU's proposal in a timely fashion.

Further, the Commission finds it reasonable to grant MDU's proposal to consolidate Rate 135 with Rate 100 upon MDU's compliance with other Rate 100 concerns addressed below.

Rate 100

Rate 100 was described by MDU in its initial rate application as "a new rule which will cover common Company business practices in a generic fashion." The Commission has concerns about portions of this proposed tariff and denies approval of Rate 100 until MDU makes the following revisions:

"Company Liability - Continuity of Service," says MDU "will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of same" (emphasis added). The Commission finds this sentence should be amended to make clear that the utility is liable for damages resulting from its own negligence.

The Commission believes the "Force Majeure" section of Rate 100 is unnecessarily long and its provisions difficult to understand because of excessive use of legal jargon. The Commission finds this section should be rewritten in plain language so that its meaning is clear to the average customer. Montana Power Company's tariff on this subject (Section 8.2B) provides a model for MDU's reference.

Under "Customer Obligations - Application for Service," one sentence reads: "The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account." The Commission will not require MDU to revise or delete this sentence, but advises MDU that the Commission will not condone a Company policy of denial of service to applicants who refuse to provide information that has no bearing on the Company's provision of service. A prospective customer may well refuse to answer some of the questions on MDU's present application form in the belief the Company is asking for information that is not reasonable.

PART 6

PSC TAX RATE CHANGE

On August 1, 1989 the Commission issued Interim Order No. 5420 which determined on a generic basis the proper ratemaking treatment for the change in the PSC tax rate (tax rate). Basically, that order required all utilities currently collecting the old 0.3 percent tax rate to decrease their tariffed rates by August 29, 1989, to reflect the current 0.18 percent tax rate (Order No. 5420, Finding of Fact No. 4).

On September 1, 1989 the Commission received comments from MDU requesting an alternative treatment for its natural gas tariffs. MDU explained in its comments that it may soon require tariff changes due to the imminent issuance of rate orders in Docket No. 88.11.53 and the next gas tracker filing. To avoid the possibility of two tariff filings within a short period of time, the Company was willing to track the excess revenues generated by the current tariffed rates versus the rates that would be required to reflect the tax rate change. The excess revenues collected by the Company would then be returned to the ratepayers through rates at a time coinciding with the future rate changes. The change in the tax rate would also be fully reflected in tariffs at that time.

In an effort to mitigate duplication of costs associated with two separate tariff filings that would be required of MDU, the Commission determined that the alternative treatment was more reasonable for MDU's natural gas utility.

This Order in the current Docket used the old 0.3 percent tax rate to reflect pro forma PSC tax expenses. The excess revenues were to be tracked from August 29, 1989, until the effective date of this Order. The Commission finds it reasonable to return the excess revenues to MDU's customers through the unreflected account in the next tracker proceeding. MDU is required to submit work papers and a demonstration showing how these impacts are to be reflected in the next tracker proceeding. The tax rate change itself must be reflected by MDU when it makes its compliance tariff filings in this Docket.

CONCLUSIONS OF LAW

The Applicant, Montana-Dakota Utilities Company, furnishes natural gas service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

The Commission properly exercises jurisdiction over the Applicant's rates and operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

The Commission has provided adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket. Title 2, Chapter 4, MCA.

The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory. Section 69-3-330, MCA.

ORDER

1. The Montana-Dakota Utilities Company shall file rate schedules which reflect increased annual revenues of $452,636 in lieu of, rather than in addition to, interim rates. The total annual gas revenues of Montana-Dakota Utilities Company will be approximately $47,516,972.

2. All motions and objections not ruled upon are denied.

3. Rate schedules filed shall comport with all Commission determinations set forth in this Order.

4. MDU is directed to comply fully with all findings contained in the body of this Order.

5. MDU is directed to file tariff sheets and supporting workpapers in compliance with this Order no later than 12 working days following the service date of this Order.

6. MDU shall design rates to generate authorized revenues which are consistent with the findings entered by the Commission in this Order.

7. Rates shall not be approved until such time as MDU adequately complies with information requested in this Order.

8. In submitting tariffs complying with this Order, MDU shall also submit workpapers detailing billing determinants, final rates, and revenues generated for the existing and resulting rate design of each class.

9. MDU shall provide the Montana Consumer Counsel copies of all resulting tariffs and workpapers also provided to the Commission staff.

10. This Order is effective for services rendered on and after December 1, 1989.

DONE AND DATED at Helena, Montana this 1st day of December, 1989 by a 3-0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Vice Chairman

WALLACE W. "WALLY" MERCER, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Ann Peck

Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.